Annual Report to Alaska Department of Environmental Conservation

Commitment to Corrosion Monitoring
Year 2009

Prepared by
Corrosion, Inspection and Chemicals (CIC) Group
BP Exploration (Alaska), Inc.

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Commitment to Corrosion Monitoring
Year 2009

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Part 1 – Overview

Overview

Alaska and BP have a shared history that dates back nearly 50 years. BP is proud of its history in Alaska, and we are committed to growing our business and creating opportunities for the future.

Each year, BP Exploration (Alaska) Inc. (BPXA) dedicates extensive resources to the corrosion monitoring and mitigation programs for BPXA operations in Alaska. We believe that the results presented in this report illustrate our devotion to continuous improvement and aspiration of our corporate goals.

This is the tenth and final annual report meeting the commitment made by BPXA to the State of Alaska to provide a regular review of BPXA's corrosion monitoring and management practices for non-common carrier pipelines on the North Slope under the Charter Agreement. The contents of this report reflect the Work Plan[1] agreed jointly between BPXA, Phillips and ADEC, the Guide for Performance Metric Reporting[2], and feedback from previous ADEC reports. As requested by ADEC in 2007, the report is now divided into five main parts.

Part 1 provides an overview of this annual report.

Part 2 describes enhancements to BPXA's corrosion monitoring and management practices, and discusses significant project achievements.

Part 3 presents a summary of the results from corrosion monitoring and management activities conducted through December 2009.

Part 4 contains information regarding the BPXA operated fields within the Greater Prudhoe Bay (GPB) Business Unit. This consists principally of fluids produced from Prudhoe Bay, Lisburne, Point McIntyre and Niakuk field areas but also includes smaller volumes of fluids from satellite accumulations.

Part 5 contains information regarding the BPXA operated fields within the Alaska Consolidated Team (ACT) Business Unit. ACT principally handles fluids from the Endicott, Badami, Milne Point and Northstar field areas. As with GPB, several smaller satellite accumulations are also produced through ACT facilities.

The report provides an overview of the corrosion management process, provides data and discusses the corrosion control, monitoring, inspection and fitness-for-service programs. In concert, these individual programs form the core of the integrity/corrosion management system; designed to deliver our corporate goal of no accidents, no harm to people and no damage to the environment[3].

[1] Appendix 2 (a) 2000 Work Plan

[2] Appendix 2 (b) Guide for Performance Metric Reporting

[3] "Our Values", BP America Inc., http://www.bp.com/

The corrosion management program reflects the core values of BP; demonstrating the attributes of innovation, performance-driven activity, environmental leadership and being a force for progress.

Innovation is evident in several areas, from the development of more effective corrosion inhibitors and corrosion inhibition programs, to the application of new inspection technologies. These innovations are only made possible by working closely with partners, major suppliers and the regulatory community, to bring the best available technology to Alaskan oilfields.

Performance management and the drive for improved performance are central to all aspects of the corrosion management program. This report demonstrates an on-going effort to improve corrosion management. Since 1992, average corrosion rates have been reduced by a factor of ten in the cross-country pipelines that transport a mixture of oil, water and gas (3-phase). Consistent with the pledge to openly report both good and bad performance, the report highlights areas for improvement and the plans in-place to deliver performance improvement.

Environmental protection and corrosion management are closely linked. Our improvements in corrosion management have resulted in lower corrosion rates and a lower risk of loss of containment. Opportunities to improve environmental performance will continue to be sought and the ongoing investment in pipeline inspection and repairs is but one example of the continued emphasis in this area.

Progressive evolution of the corrosion management programs is an on-going activity driven by changing field conditions and the desire to improve performance. Progress involves the continued refinement of existing programs, but also, the development and implementation of new programs and corrosion management technologies.

The current corrosion management process has delivered a significantly improved level of corrosion control for the North Slope energy infrastructure. Notwithstanding the successes, the corrosion management program continues to be focused on the future in order to maintain the current level of control and where necessary, implement the actions necessary to improve performance.

With the Charter Agreement now expired and the last of the ten annual reports now submitted, BPXA looks forward to working with ADEC on what future reports, if any, might be submitted and the scope of these reports if they are.

Part 2 – Significant Enhancements to Corrosion Programs

Significant Enhancements to Corrosion Programs

In 2009 BPXA adopted a comprehensive Operating Management System (OMS) that integrates existing management systems and provides a common framework for achieving safe and reliable operations. The OMS framework defines a set of operating requirements which drive continuous risk reduction and disciplined behavior to challenge and help eliminate unsafe acts and conditions. It is built around people, plant, process and performance, and this is reflected in the enhancements to our corrosion programs in 2009. Some significant enhancements are set out below.

People

BPXA's targeted recruiting campaign has continued to enhance the capacity and competency of the corrosion teams. The Anchorage based Strategy and Planning Team grew from 31 to 38 staff this year.

The Corrosion Control Strategy Implementation Team (CCSIT) formed in 2007 continues to create and assist in implementing corrosion control strategies. The North Slope based team grew from 10 to 11 personnel embedded within the field operations. Seven CCSIT staff continued to be based out of Anchorage.

Plant

The MPU Tract 14 produced water and 3-phase flow lines were replaced with above grade piping that is equipped for maintenance pigging and ILI.

Infrastructure upgrades to the 24" Gas Lift (GL) pipeline system allowed for subsequent in-line inspections of the three segments using smart pig technology. The upgrades included modification and installation of permanent piping infrastructure on each of the three segments. This addition facilitates the installation of pig launching and receiving equipment allowing for regular inspection of the pipeline system in order to provide fitness for service assurance.

BP successfully deployed a new "free swimming" inline internal inspection instrument consisting of high resolution Phased Array ultrasonic technology in several small diameter produced water flowlines. This technology has increased our In-line inspection program capability with additional deployments scheduled for 2010. In addition, further field trails were successfully completed on the external eMFL and Electro-Magnetic Pulse Wave technologies primarily dedicated to furthering BP's corrosion under insulation detection capabilities.

CUI Preventive Barriers, used by the offshore industry have been tested in the laboratory and at a test facility in Fairbanks. Laboratory testing conducted by BP Exploration and Production Technology (EPT) in Houston indicates CUI Barriers are effective in preventing moisture ingress and reducing the CUI corrosion rate. Optimum designs were installed as a trial on the North Slope in October. A monitoring baseline has been established by which to evaluate long term performance.

Process

The geographic information system (GIS) was enhanced in 2009 by adding well lines to the application and incorporating a pipeline alignment sheet generator for displaying engineering data (including corrosion inspections) in relation to mapped pipelines and land based features. The well line effort consists of the addition of more than 4,000 discrete pipe routes and pipeline alignment sheets have been created for approximately 400 major flow lines.

A novel statistical tool-set, providing mathematical evaluation for sufficient pipeline inspection coverage and extreme value analysis of corrosion defects, has been incorporated into the quarterly RAPID (Relative Assessment of Piping Integrity Data) reporting for well lines and flow lines. The combined output is intended to assist planning inspection, corrective action, and renewal strategies.

Improved analytical techniques were developed and evaluated for determination of corrosion inhibitor residuals in fluids downstream of treatment. The advanced analytical techniques provide information about specific chemical components of the inhibitor and the partitioning behavior of inhibitor components in different fluids. This information will be used to optimize the application of corrosion inhibitors.

Use of a corrosion monitoring sidestream device was initiated in the produced water system at GC2 to provide improved understanding of corrosion initiation mechanisms and to aid in developing best-in-class mitigation chemistry. Initial baseline tests were performed on coupons from the device. Testing included advanced molecular microbiological analysis of surface deposits and examination of pit initiation mechanisms using scanning electron microscopy (SEM) and white light Interferometry.

Evaluation and testing of a formalized risk based assessment (RBA) software tool began in 2009. The overall project is focused on applying risk based assessment processes for pipelines using a software tool to implement the algorithm.

Six (6) Asset Specific Corrosion Control Plans (ASCCP) were developed including the Central Gas Facility (CGF), Central Compressor Plant (CCP), Central Power Station (CPS), Full Field (FF), Grind and Inject (G&I) and Seawater System (SW). The ASCCPs represent operational implementation of the overall Corrosion Control Strategy and will be adopted through the Management of Change process.

Advancements were made in the protocol for CI Optimization in the 3-phase system, driving consistency and technical rigor to corrosion inhibitor rate adjustment process and further integrating operational performance data.

<u>Performance</u>

Continuous improvement in the corrosion management programs was observed in several key metrics;

> Overall delivery of maintenance pigging continues to increase. For GPB 3-phase oil lines the annual percentage of completed maintenance pig runs improved from 66% in 2008 to 89% in 2009.
>
> For the maintenance pigging at Milne Point, 100% of the scheduled pig runs were completed for the PW lines and 96% were completed for the 3-phase lines. At Endicott, 100% of the scheduled maintenance pig runs were completed.
>
> Twenty-eight ILI runs were performed on GPB pipelines - nearly twice the number of ILI runs as performed in 2008.

External corrosion inspection activity in 2009 was essentially double the level of activity in 2008. A historical high of over 90,000 inspections was completed in 2009.

The target of 200 cased segment inspections for 2009 was well exceeded; 524 segments were inspected using a combination of techniques. In addition thirteen casing excavation inspections were completed.

At Northstar, the percentage of water disposal well inspection increases declined from 11% in 2008 to 6% in 2009.

For the year, 99% of the 3-phase well line coupons were below the 2 mpy general corrosion target and only 0.2% of the coupons exhibited a pit rate >20 mpy. The average corrosion rate for weight loss coupons in 3-phase well lines has decreased each year since 2005 and has been below the 2 mpy target every year since 1997.

A number of program reviews were also conducted during 2009, including:

GPB corrosion management program updates, conducted with major GPB partners.

A continuous improvement workshop was held to promote Corrosion Under Insulation Program improvements. Participants included local Anchorage and North Slope employees as well as senior engineering staff from Houston, USA and Sunbury, UK offices.

ADEC ‘Meet and Confer’ sessions were held twice per the Charter Agreement. In addition to the formal reviews, a field trip was organized on the North Slope for ADEC personnel to witness elements of the corrosion management program first-hand.

BPXA also supported development of the Advanced Internal Corrosion for Pipelines course for NACE International and hosted the inaugural offering of the course in June 2009.

Part 3 – Summary of BPXA Programs

Section A GPB Corrosion Program Summary

Section A.1 GPB Corrosion/Mechanical Related Leaks and Repairs

A measure of corrosion management program efficacy is the number of corrosion related leaks. The ultimate goal of this measure is no corrosion related leaks.

Target:	No Leaks
KPI:	Number of Leaks
Section Reference:	Part 4 - Section C.2 Corrosion and Structural Related Leaks

1. There were six corrosion/mechanical related leaks of which;
    a. There was one external corrosion related leak in a 3-phase flow line.
    b. There were two mechanical/fatigue related leaks; one on a 3-phase flow line and the other on diesel service piping.
    c. There was one leak due to mechanical/ice in a 3-phase flow line.
    d. There was one nitrogen leak due to internal corrosion on a flow line.
    e. One leak occurred in a produced water well line due to internal corrosion.
2. There were no corrosion related leaks in 3-phase well lines or piping in the seawater, processed oil or gas systems.
3. There were 72 mechanical repairs identified as a result of external corrosion.
4. There were 14 mechanical repairs identified as a result of internal corrosion.

Section A.2 GPB Corrosion Monitoring

A principal objective of corrosion monitoring is to measure the effectiveness of applied mitigation programs. The primary monitoring techniques employed in this program are intrusive weight loss coupons (WLC) and Electrical Resistance Probes (ER Probe) which provide the feedback for corrective action when corrosion rate targets are exceeded.

Program:	Weight Loss Coupon
Target:	<2 mils per year (mpy) general
KPI:	% Conformance WLC <2 mpy
Section Reference:	Part 4 -Section A.1 - Weight Loss Coupons and Probes

1. 6,494 coupons were utilized to monitor the effectiveness of the mitigation programs.
2. The 3-phase flow line WLC data showed nearly 100% less than 2 mpy with an average general corrosion rate of 0.14 mpy.
3. Water injection flow line (produced and seawater) WLC data showed 86% less than 2 mpy with an average general corrosion rate of 1.27 mpy.
4. Processed oil flow line WLC data showed 100% less than 2 mpy with an average general corrosion rate of 0.07 mpy.
5. The 3-phase well line WLC data showed 99% less than 2 mpy with an average general corrosion rate of 0.24 mpy.
6. Majority service produced water well line WLC showed 99% less than 2 mpy and average general corrosion rate of 0.15 mpy.
7. The 100% produced water service well line WLC showed 100% less than 2 mpy and average general corrosion rate of 0.07 mpy.
8. Majority service seawater well line WLC showed 97% less than 2 mpy and average general corrosion rate of 0.33 mpy.
9. The 100% seawater service well line WLC showed 97% less than 2 mpy and average general corrosion rate of 0.33 mpy.

Program:	Weight Loss Coupon
Target:	<20 mils per year (mpy) pitting
KPI:	% Conformance WLC <20 mpy
Section Reference:	Part 4 -Section A.1 - Weight Loss Coupons and Probes

1. The 3-phase flow line WLC pitting corrosion data showed 100% less than 20 mpy.
2. Water injection flow line (produced and seawater) WLC pitting corrosion data showed 99% less than 20 mpy.
3. Processed oil flow line WLC pitting corrosion data showed 100% less than 20 mpy.
4. The 3-phase well line WLC pitting corrosion data showed 100% less than 20 mpy.
5. Majority service produced water well line WLC pitting corrosion data showed 99% less than 20 mpy.
6. The 100% produced water service well line WLC pitting corrosion data showed 100% less than 20 mpy.

7. Majority service seawater well line WLC pitting corrosion data showed 100% less than 20 mpy.
8. The 100% seawater service well line WLC pitting corrosion data showed 100% less than 20 mpy.

Program:	Electrical Resistance Probe
Target:	<2 mils per year (mpy)
KPI:	Conformance <2 mpy
Section Reference:	Part 4 - Section A.1 - Weight Loss Coupons and Probes

1. 108 ER probes were used for corrosion monitoring in GPB flow lines.
2. The 3-phase flow line ER Probes showed 80% of the data was <2 mpy.
3. Only three ER probes showed results that resulted in mitigation actions.

Based on the internal corrosion monitoring results from coupons and probes, continuous improvement in corrosion control was observed for 3-phase flow lines and well lines, and processed oil flow lines. The WLC results for produced water and seawater lines met the target criteria for general corrosion and pitting rates however performance in some categories was slightly lower the 2008 results.

Section A.3 GPB Corrosion Inhibition Program

For internal corrosion control, a principal means of mitigation is through the carefully monitored application of corrosion inhibitors.

Program:	Corrosion Mitigation – Corrosion Inhibitor (CI)
Target:	Control corrosion to acceptable levels
KPI:	Target versus actual CI usage, injection volumes (ppm)
Section Reference:	Part 4 -Section A.2 - Corrosion Inhibition

1. In the 3-phase systems, the field wide average inhibitor concentration increased slightly from 162 to 166 ppm.
2. The total 3-phase corrosion inhibitor usage was 2.42 million gallons (winter equivalent) which was delivered at just above 100% of the target volume in the 3-phase flow lines and well lines.

3. The corrosion inhibitor usage in the produced water system averaged 2,800 gpd which equates to 970,000 gallons per year.
4. The corrosion inhibitor usage in the processed oil system averaged 132 gpd which equates to 48,000 gallons per year.

The effectiveness of corrosion mitigation, as a result of the application of corrosion inhibition, is determined from corrosion monitoring and inspection programs. Corrosion monitoring data is a leading indicator and inspection data is a lagging indicator of corrosion mitigation efforts.

Section A.4 GPB Maintenance Pigging Program

Maintenance pigging is another form of internal corrosion mitigation and management. The metrics reported here include the number of scheduled maintenance pig runs, the number of scheduled runs completed, and the percent of scheduled runs completed, presented by quarter. This is the third report year in which maintenance pigging data has been included.

Program:	Corrosion Mitigation – Maintenance Pigging
Target:	Control corrosion to acceptable levels
KPI:	Number of maintenance pig runs planned vs. number of runs completed and percent completed.
Section Reference:	Part 4 - Section A.3 - Maintenance Pigging

1. A total of 462 maintenance pigs were planned and 313 were completed (68%).

Factors outside the control of the program such as weather, operations, flow conditions and launcher/receiver outages, often affect pigging schedules. Inspection and repair of pig launchers and receivers continues to be conducted.

Section A.5 GPB External Corrosion Inspection Program

The plan for the external corrosion program includes comprehensive inspection coverage of equipment susceptible to corrosion under insulation (CUI), minimizing loss as a result of external corrosion failures and assuring that the equipment is fit-for-service (FFS) and safe to operate.

Program:	Corrosion Under Insulation
Target:	90,000 inspections
KPI:	% of locations inspected with external corrosion
Section Reference:	Part 4 - Section B.1.1 - External Inspection Program Results

1. Of the 90,404 external corrosion inspections completed, 2% were found with corrosion degradation. The level of CUI inspection activity completed in 2009 was a best-ever performance.

Unlike internal corrosion where mitigation can be managed through chemical inhibition, mechanical cleaning and/or operational controls, CUI is managed through detection and repair. Once CUI has been found through inspection activities, locations are scheduled for insulation and by-product removal, fit-for-service assessment, mechanical repair if needed and rehabilitation of the insulation system.

Section A.6 GPB Cased Pipe Program

The overall plan for the cased pipe program is to employ the best inspection technology available for cased pipe segments at road and/or animal crossings where historically, the prominent threat has been external corrosion. Excavation of crossings, as required, is then performed to mitigate active corrosion and assure that the equipment is fit-for-service and safe to operate.

Program:	Cased Pipe Inspection
Target:	200 inspections
KPI:	Inspection increases determined from repeat examinations.
Section Reference:	Part 4 - Section B.1.2 - Cased Piping Survey Results

1. There were 368 LRGWUT, 147 ILI and 13 excavation inspections performed, for a total of 528 examinations on 524 cased pipe segments (4 segments were inspected twice).
2. The program consisted of 392 repeat examinations/monitoring and excavations; no increases were reported.

Section A.7 GPB Internal Inspection Program

The objective of the internal inspection program is to provide widespread inspection coverage of equipment susceptible to internal corrosion degradation. Corrosion mechanisms and rate of metal loss are also identified to minimize failures and assure that the equipment is fit-for-service and safe to operate.

Program:	Internal Inspection Program
Target:	65,000 inspections split between field piping (29,000) and facility equipment (36,000)
KPI:	% of locations inspected with increased metal loss
Section Reference:	Part 4 - Section B.2 - Internal Inspection Program Results

1. There were 20,769 inspections completed on field piping in oil and water service.
    a. There were 10,391 inspections on 3-phase flow lines, with 1% showing an increase.
    b. There were 6,340 inspections on 3-phase well lines, with 3% showing an increase.
    c. There were 2,181 inspections on water injection flow lines, with 4% showing an increase.
    d. There were 1,595 inspections on water injection well lines, with 5% showing an increase.
    e. There were 262 inspections on processed oil flow lines with 1% showing an increase.

The percentage of inspections showing corrosion increases was lower for water service well lines and flow lines.

Section A.8 GPB Internal Corrosion Summary by Service

This section presents a summary of internal corrosion key indicators by service type for GPB. For comparative purposes, data from the current report year and the previous year are presented below.

Service	Average WLC Corrosion Rate, mpy		% WLC Corrosion Rate < 2 mpy		% WLC Pit Rate < 20 mpy		% Internal Inspection Increases		Internal Corrosion Related Leaks	
	2008	2009	2008	2009	2008	2009	2008	2009	2008	2009
3-phase flow lines	0.19	0.14	100%	100%	100%	100%	1%	1%	-	1[1]
3-phase well lines	0.32	0.24	98%	99%	100%	100%	2%	3%	-	-
Water injection flow lines	0.63	1.27	92%	86%	97%	99%	5%	4%	-	-
Processed Oil flow lines	0.13	0.07	100%	100%	100%	100%	1%	1%	-	-
Maj. Service PW well lines	0.11	0.15	100%	99%	100%	99%	6%	5%	-	1
100% PW well lines	0.10	0.07	100%	100%	100%	100%				
Maj. Service SW well lines	0.26	0.33	100%	97%	100%	100%			1	-
100% SW well lines	0.27	0.33	100%	97%	100%	100%				

Note 1 - Nitrogen service.

GPB Summary Table A.1 Internal Corrosion Summary Data by Service Type

The average corrosion rates, percentage of WLC with corrosion rates <2 mpy and percentage of WLC with pitting rates <20 mpy (threshold levels) for each service type illustrate that overall, a high level of success is being achieved by the corrosion management program. Performance metrics were consistent with those of the previous year, with incremental improvements observed for many metrics. Water injection flow lines showed lower performance in the WLC metrics but fewer internal corrosion inspection increases; this is recognized as an area for continuous improvement.

While WLC results describe near-term corrosion management performance, leak history and internal inspection results are measures of longer-term progress in corrosion control. The data this year continue to show fewer internal inspections with increased corrosion. This same trend extending over the past five years is discussed later in the report. Although the internal corrosion management efforts are largely successful and show continuing improvement, optimization of mitigation and monitoring in all systems continues to be a long-term goal.

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Section B ACT Corrosion Program Summary

Section B.1 ACT Operating System Overview

Alaska Consolidated Team (ACT) Performance Unit consists of four producing areas: Endicott, Milne Point Unit (MPU), Northstar and Badami. Each of the producing fields within ACT has unique characteristics and challenges related to corrosion management.

Milne Point - Located approximately 25 miles west of Prudhoe Bay, the field began production in 1985. On January 1st, 1994, BPXA acquired a majority working interest and assumed operatorship. Since 1994, production and proven reserves have been increased; Milne Point production averaged approximately 28,900 bpd in 2009.

Endicott - Located northeast of Prudhoe Bay, Endicott consists of two islands, the main Production Island (MPI), and the satellite-drilling island (SDI) at the end of a causeway. Endicott 3-phase production piping is fabricated largely of duplex stainless steel, which significantly reduces the corrosion threat and hence the environmental risks. Endicott production averaged approximately 11,500 bpd in 2009.

Badami - Remotely located east of Prudhoe Bay, Badami has a relatively low production volume due to challenging reservoir conditions. The Badami production facilities are constructed using a much smaller surface footprint than GPB and do not have permanent road access, therefore having a much reduced impact on the environment. Production from Badami was placed in warm shutdown in August of 2007, prior to which production averaged approximately 600 bpd.

Northstar - Northstar is the first offshore oil field in the Beaufort Sea not connected to land by a causeway. As with Badami and other recent developments, Northstar drilling and production operations are built on a smaller footprint than the original North Slope facilities. Northstar production averaged approximately 21,900 bpd in 2009.

ACT Summary Table B.1 illustrates, on a relative basis, the unique corrosivity of each producing field within ACT along with the materials of construction and forms of corrosion mitigation. GPB is included in the table for comparative purposes. Listed in the table are, for each field, the typical water cut in percent, average wellhead temperature, and the percent CO_2 in the produced gas.

Badami, MPU, and Northstar production fluids have a lower corrosivity compared with GPB. Endicott's production fluid characteristics are more corrosive than GPB and this corrosion risk is mitigated largely through the use of duplex stainless steel (DSS).

ACT Summary Table B.2 shows the ACT fields combined are of a much smaller scale than GPB. For example, neither Northstar nor Badami have any significant non-common carrier cross-country flow lines. Also, it should be noted, that when comparing GPB and ACT facilities, these facilities vary in age from more than 30 years for GPB to approximately eight years for Northstar.

	Prod Fluid Characteristics				Material of Construction [a]			
					Production		Injection	
Field	**H_2O (%)**	**T (°F)**	**P_{CO_2}(%)**	**CR [b]**	**WL**	**FL**	**WL**	**FL**
GPB	76	105	12	H	CS+CI	CS+CI[c]	CS+CI	CS+CI
Endicott	94	150	17	H	DSS	DSS	CS+CI	CS+CI
Milne Point	70	85	0.5	L/M	CS	CS [d]	CS+CI	CS+CI
Northstar	41	149	7[e]	M	CS+CI	N/A	N/A	N/A
Badami	0	65	0	L	CS	N/A	N/A	N/A

Notes
(a) CS is carbon steel, CI is corrosion inhibitor, DSS is duplex stainless steel
(b) Unmitigated relative corrosion rate, H – high, M – medium, and L - low
(c) There are a limited number of Duplex Stainless Steel flow lines in GPB
(d) Two production flow lines are inhibited at MPU
(e) Northstar CO_2 has increased from 5-6% at startup to 8% due to gas injection from GPB containing 12% CO_2.

ACT Summary Table B.1 Relative Corrosivity of BPXA North Slope Production

Metric	**ACT**	**GPB**	$\frac{\textbf{ACT}}{(\textbf{ACT}+\textbf{GPB})}$**%**
Number of Production Trains	4	21	16%
Number of Prod and Inj. Wells	408	1,498	21%
Non-common carrier FL miles	105	1,350	7%
Total Acreage	75,000	203,000	27%

ACT Summary Table B.2 Illustrative Comparison of Scale between ACT and GPB

Section B.2 ACT Corrosion/Mechanical Related Leaks and Repairs

A measure of corrosion management program efficacy is the number of corrosion related leaks with the ultimate goal of “no leaks”.

Target:	No Leaks
KPI:	Number of Leaks
Section Reference:	Part 5 - Section C - ACT Corrosion & Structural Related Repairs and Spills

1. No leaks occurred at Endicott, Milne Point, Northstar or Badami.
2. There were three repairs related to external corrosion.
3. There was one repair related to internal corrosion.

Section B.3 ACT Corrosion Monitoring

A principal objective of corrosion monitoring is to measure the effectiveness of mitigation programs. In ACT, the primary monitoring techniques employed in this program are intrusive weight loss coupons (WLC) which provide the feedback for corrective action when corrosion rate targets are exceeded.

Program:	Weight Loss Coupon
Target:	<2 mils per year (mpy) general
KPI:	% Conformance WLC <2 mpy
Section Reference:	Part 5 - Section A - ACT Corrosion Monitoring and Mitigation

1. Endicott water injection system WLC showed 100% less than 2 mpy and an average corrosion rate of 0.01 mpy.
2. The Endicott oil production system, which is not inhibited, showed 84% WLC less than 2 mpy and an average corrosion rate of 0.91 mpy.
3. Milne Point oil production system WLC showed 97% less than 2 mpy and an average corrosion rate of 0.30 mpy.
4. Milne Point water injection system WLC showed 100% less than 2 mpy and an average corrosion rate of 0.10 mpy.
5. Northstar oil production system WLC showed 96% less than 2 mpy and an average corrosion rate of 0.49 mpy.
6. Northstar water injection system upstream WLC showed 100% less than 2 mpy and an average corrosion rate of 0.07 mpy.
7. Badami currently has no WLC-monitoring program, and relies on the inspection program to provide corrosion control feedback.

Program:	Weight Loss Coupon
Target:	<20 mils per year (mpy) pitting
KPI:	% Conformance WLC <20 mpy
Section Reference:	Part 5 - Section A - ACT Corrosion Monitoring and Mitigation

1. Endicott water injection system WLC pitting data showed 100% less than 20 mpy.
2. The Endicott oil production system, which is not inhibited, showed 93% WLC pitting data less than 20 mpy.
3. Milne Point oil production system WLC pitting data showed 99% less than 20 mpy.
4. Milne Point water injection system WLC pitting data showed 100% less than 20 mpy.
5. Northstar oil production system WLC pitting data showed 100% less than 20 mpy.
6. Northstar water injection system upstream WLC pitting data showed 99% less than 20 mpy.
7. Badami currently has no WLC monitoring program, and relies on the inspection program to provide corrosion control feedback.

Program:	Electrical Resistance Probe
Target:	<2 mils per year (mpy)
KPI:	Conformance <2 mpy
Section Reference:	Part 5 - Section A - ACT Corrosion Monitoring and Mitigation

1. Eleven ER probes were used for monitoring corrosion rates in flow lines.
2. One mitigation action was required to address an ER probe exception.

Section B.4 ACT Corrosion Inhibition Program

For internal corrosion control, a principal means of mitigation is through the application of corrosion inhibitors. The means of corrosion mitigation used throughout the ACT assets varies with the service type, system design, operational conditions and other factors.

Program:	Corrosion Mitigation – Corrosion Inhibitor (CI)
Target:	Control corrosion to acceptable levels
KPI:	Target versus actual CI usage, injection volumes (ppm)
Section Reference:	Part 5 - Section A - ACT Corrosion Monitoring and Mitigation

The inhibitor targets for the Endicott produced water, Milne Point produced water and Northstar 3-phase systems were met in 2009.

Endicott

1. The annual target volume for produced water corrosion inhibitor at Endicott was 105,377 gallons; the actual volume of CI used was 111,999 gallons. The annual average CI concentration was 41 ppm, which met the target concentration for the year.

Milne Point

1. The annual corrosion inhibitor target volume for 3-phase production was 117,360 gallons; the actual volume of CI used was 115,484 gallons. The annual average CI target concentration for 3-phase production at Milne was 103 ppm; the annual average delivered concentration was 102 ppm.
2. The annual corrosion inhibitor target volume for produced water was 73,520 gallons and the actual volume of CI used was 73,504 gallons. The annual average CI target concentration for produced water was 55 ppm; the annual average delivered concentration was 57 ppm.

Northstar

1. The annual target volume for 3-phase production corrosion inhibitor at Northstar was 37,733 gallons; the actual volume of CI used was 37,874 gallons. The target concentration was 165 ppm; the annual average CI concentration was 167 ppm.

Badami

1. The field has been in warm shut-down since August 2007.

Section B.5 ACT Maintenance Pigging Program

The quarterly maintenance pigging performance is provided for 2006 through 2009 in this year's report.

Program:	Corrosion Mitigation – Maintenance Pigging
Target:	Control corrosion to target levels
KPI:	Number of maintenance pig runs planned vs. number of runs completed and percent completed.
Section Reference:	Part 5 - Section A - ACT Corrosion Monitoring and Mitigation

A maintenance pigging program for Endicott and Milne continued to be delivered according to plan.

1. For the maintenance pigging at Milne Point, 61 pig runs were planned and completed for the PW lines (100%). For the 3-phase lines 78 maintenance pig runs were planned and 75 were completed (96%).

2. For Endicott, 12 maintenance pig runs were planned and all were completed (100%).

Section B.6 ACT External Inspection Program

Highlights of the external inspection program results for each ACT asset are presented below.

Program:	Corrosion Under Insulation
Target:	3,500 inspections
KPI:	% of locations inspected with external corrosion
Section Reference:	Part 5 - Section B - ACT External/Internal Inspection

The total number of external inspections for ACT was 4,738.

Endicott

1. 1,361 external inspections were performed; 3% showed inspection increases.

2. Cased flow lines continue to be inspected at pre-established intervals.

Milne Point

1. Overall, 3,369 external inspections were performed.

2. Of the repeat external TRT inspections, <1% showed CUI.

Northstar

1. Three external inspections were performed on produced water headers. One external inspection was at a repeat location and showed a slight inspection increase, while the other two locations were baseline inspections.

Badami

1. Five baseline external inspections were performed.

Section B.7 ACT Internal Inspection Program

The objective of the internal inspection program is to provide widespread inspection coverage of equipment susceptible to internal corrosion degradation. Corrosion mechanisms and rate of wastage are also identified to minimize failures and assure that the equipment is fit-for-service and safe to operate.

Program:	Internal Inspection Program
Target:	Ongoing Inspection Program in ACT Assets
KPI:	% of locations inspected with increased metal loss
Section Reference:	Part 5 - Section B - ACT External/Internal Inspection

<u>Endicott</u>

1. 4,832 internal inspections were performed.
2. One percent of the inspections showed increases in the 3-phase well lines.
3. Two percent of the frequently monitored locations on the IIWL showed minor increases.

<u>Milne Point</u>

1. A total of 4,429 internal inspections were performed.
2. The percentage of 3-phase well line inspection increases continues to remain low with only 2% of repeat locations showing an increase in corrosion activity.
3. None of the inspections showed increases on the produced water flow lines and only 1% of the inspections had increases on 3-phase flow lines.
4. The PW well lines had 3% of the inspections showing increases.

<u>Northstar</u>

1. A total of 1,036 internal inspections were completed.
2. The 3-phase system had 2% of the inspections showing increases.
3. 6% of the water disposal well inspections showed increases; an improvement over 11% in 2008.

Badami

1. There were 92 internal inspections of well lines; no inspection increases were observed.

Section B.8 ACT Internal Corrosion Summary by Service

This section presents a summary of internal corrosion key indicators by service type for ACT. For comparative purposes, data from the current report year and the previous year are presented in ACT Summary Table B.3.

Service	Average WLC Corrosion Rate mpy		% WLC Corrosion Rate < 2 mpy		% WLC Pit Rate < 20 mpy		% Internal Inspection Increases		Internal Corrosion Related Leaks	
	2008	2009	2008	2009	2008	2009	2008	2009	2008	2009
END Water Inj Pads.	0.13	0.07	100%	100%	100%	100%	2%	3%	-	-
END Water Inj FL	1.77	0.91	80%	100%	84%	100%	3%	2%	-	-
MPU Oil Prod.	0.08	0.30	100%	97%	100%	99%	1%	2%	-	-
MPU Water Inj.	0.23	0.10	100%	100%	100%	100%	1%	3%	-	-
NSTR Oil Prod	0.48	0.49	100%	96%	100%	100%	-	2%	-	-
NSTR Water, upstr	0.13	0.07	100%	100%	100%	99%	11%	6%	-	-

ACT Summary Table B.3 Internal Corrosion Summary Data by Service Type

The average corrosion rates, percentage of WLC with corrosion rates <2 mpy and percentage of WLC with pitting rates <20 mpy (threshold levels) for each service type illustrate that overall, effective corrosion control is largely present for the each of the service types. Whereas WLC results describe near-term corrosion management performance, leak history and internal inspection results point more toward long-term advances in corrosion control. The data also show reductions in the number of internal inspections with increased corrosion in most services.

Part 4 – Greater Prudhoe Bay Business Unit

GPB Section A

Corrosion Monitoring and Mitigation

Section A GPB Corrosion Monitoring and Mitigation

This section presents weight loss coupon data, ER probe results, chemical mitigation data and maintenance pigging program performance.

Section A.1 Weight Loss Coupons and Probes

This section summarizes the results of the weight loss coupon (WLC) and ER probe corrosion monitoring programs. In this section, the results of the programs are reviewed for each of the major service categories.

The number of corrosion monitoring locations by equipment type and service is summarized in GPB Table A.1.

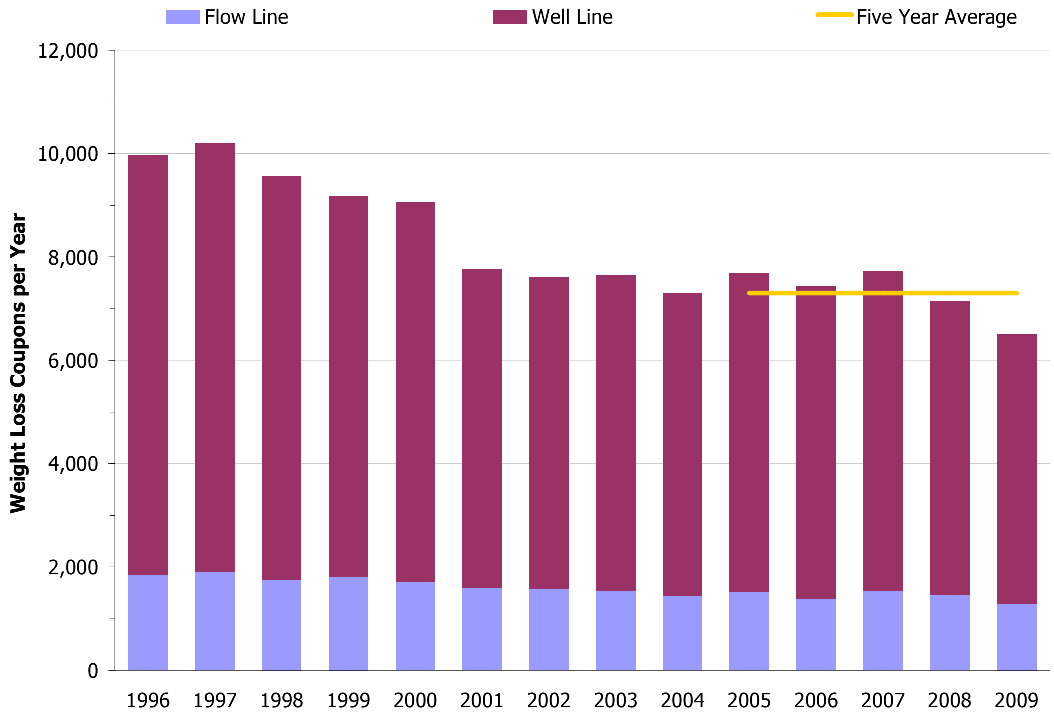
Service	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Flow Line															
3 Phase	214	307	262	265	260	248	250	252	254	241	232	179	179	182	174
Exp Oil	5	7	7	5	5	6	4	7	5	6	5	6	6	8	8
Gas	3	3	1	1	1				1						
Other	8	12	10	13	11	10	11	10	4	4	6	5	3	3	3
Water	36	37	45	43	46	45	44	44	48	38	40	38	39	38	36
Total	266	366	325	327	323	309	309	313	312	289	283	228	227	231	221
Well Line															
3 Phase	1,027	1,154	1,199	1,186	1,158	1,152	1,068	1,082	1,108	1,091	1,063	1,078	1,083	1,080	1,030
Exp Oil	-	3	3	3	3	3	3								
Gas	6	5	4	4	3	3	4	5	5	3	3	3	2	3	3
Other	29	28	29	26	24	22	21	23	13	14	18	16	11	15	10
Water	197	208	211	205	188	185	188	193	174	175	184	185	188	188	156
Total	1,259	1,398	1,446	1,424	1,376	1,365	1,284	1,303	1,300	1,283	1,268	1,282	1,284	1,286	1,199
Grand Total	1,525	1,764	1,771	1,751	1,699	1,674	1,593	1,616	1,612	1,572	1,551	1,510	1,511	1,517	1,420

GPB Table A.1 Corrosion Monitoring Locations by Equipment and Service

For each monitoring period, two corrosion coupons are typically installed and recovered from each corrosion monitoring location with the exception of those lines that are regularly maintenance pigged. For lines that are pigged for maintenance, a single flush-mounted coupon is typically used to prevent interference with the pig. The number of coupons, coupons per monitoring location and frequency of recovery continue to be adjusted over time to optimize the value obtained from the data.

Since 2001, the number of weight loss coupons used in the program has stabilized to around 7,500 coupons per year. As discussed in prior reports, there was a gradual reduction in the number of weight loss coupons being evaluated from 1997 through 2000, which reflected an on-going effort to optimize the program. The number of weight loss coupons reported for 2009 does not reflect coupons that were still in service at year-end. The number of WLC processed over time is presented in GPB Figure A.1.

Detailed corrosion coupon results for each service type are provided in GPB Table A.5 and GPB Table A.6.



GPB Figure A.1 Corrosion Monitoring Activity Statistics by Equipment

Section A.1.1 3-phase Production Systems

Section A.1.1.1 Introduction

The primary corrosion mechanism of concern in the 3-phase production system is CO_2 corrosion, in which CO_2 from the produced fluids dissolves and dissociates in the produced water to form an acidic environment. If the acidic conditions are left untreated, the environment can be corrosive to carbon steel[4,5]. The primary corrosion control method employed at GPB is the continuous addition of corrosion inhibitor to the flow lines and continuous or batch inhibitor additions in the well lines. For the 3-phase production system, the target corrosion rates for weight loss coupons are a general corrosion rate of 2 mpy or less (WLC 2 mpy) and a pitting corrosion rate of 20 mpy or less.

The 3-phase production system has benefited from consistent improvements in corrosion control since the early 1990's, with an order of magnitude reduction in the cross-country flow line corrosion rates. The reduction in corrosion rates was a direct result of the implementation of an aggressive corrosion mitigation program consisting primarily of continuous addition of corrosion inhibitor into the production fluids. This mitigation program continues to be rigorously carried out each year; the result being that the flow lines are now expected to be fit-for-service (FFS) for approximately ten times as long as was expected in the early 1990's. The correlation between corrosion inhibitor concentration and corrosion rates in 3-phase flow lines is discussed in detail in Section

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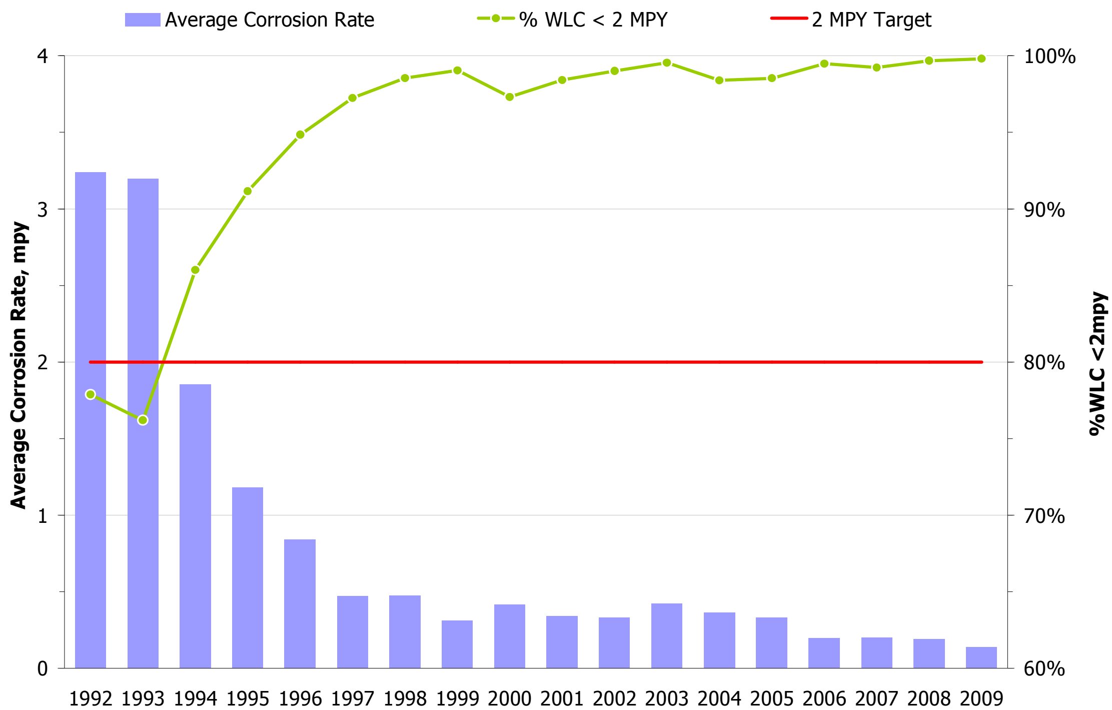
[4] Corrosion Control in Petroleum Production, Harry G Byers, NACE, 1999

[5] Corrosion Control in Oil and Gas Production, Treseder and Tuttle, NACE, 1998

A.2. A similar reduction of internal corrosion rates is also reflected in the inspection history discussed later in Section B.

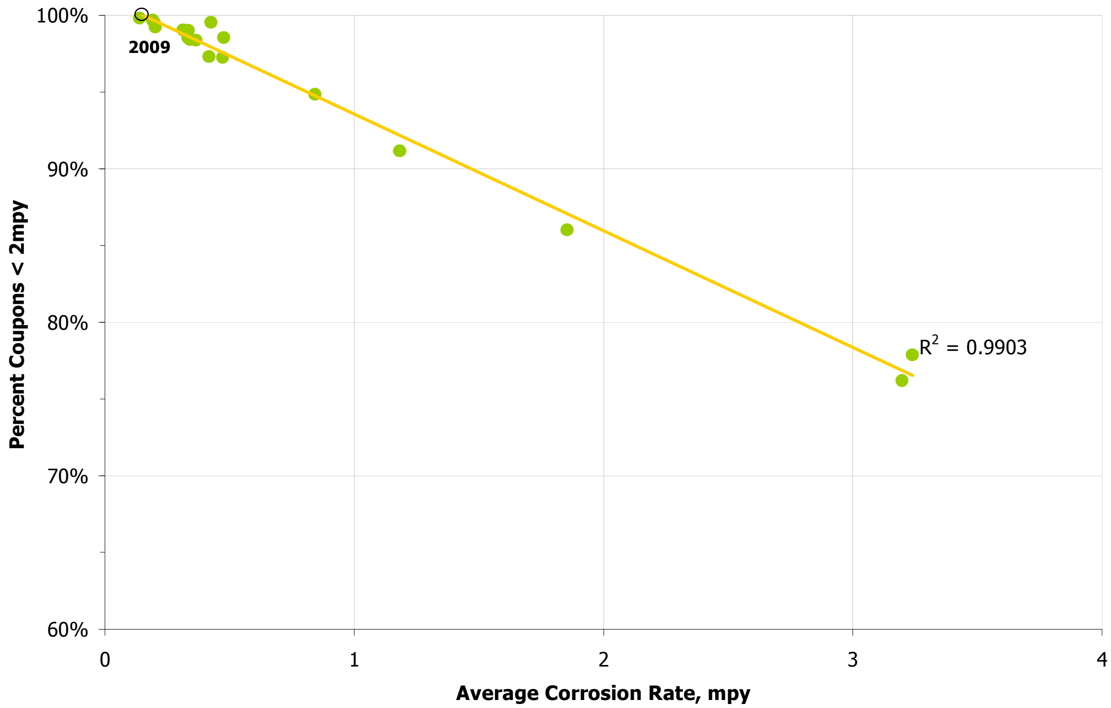
Section A.1.1.2 Cross Country Flow Line Coupons

GPB Figure A.2 shows the average corrosion rate and percentage of coupons meeting the performance standard target since 1992. The results show that the percentage of conformant flow line coupons has continued to improve since 1992. In fact, the average WLC corrosion rate has been <0.5 mpy since 1997 and <0.25 since 2006. While the data clearly point to the success of mitigation efforts, such consistently low corrosion rate values approach the limit of practical and statistical significance for this monitoring method.



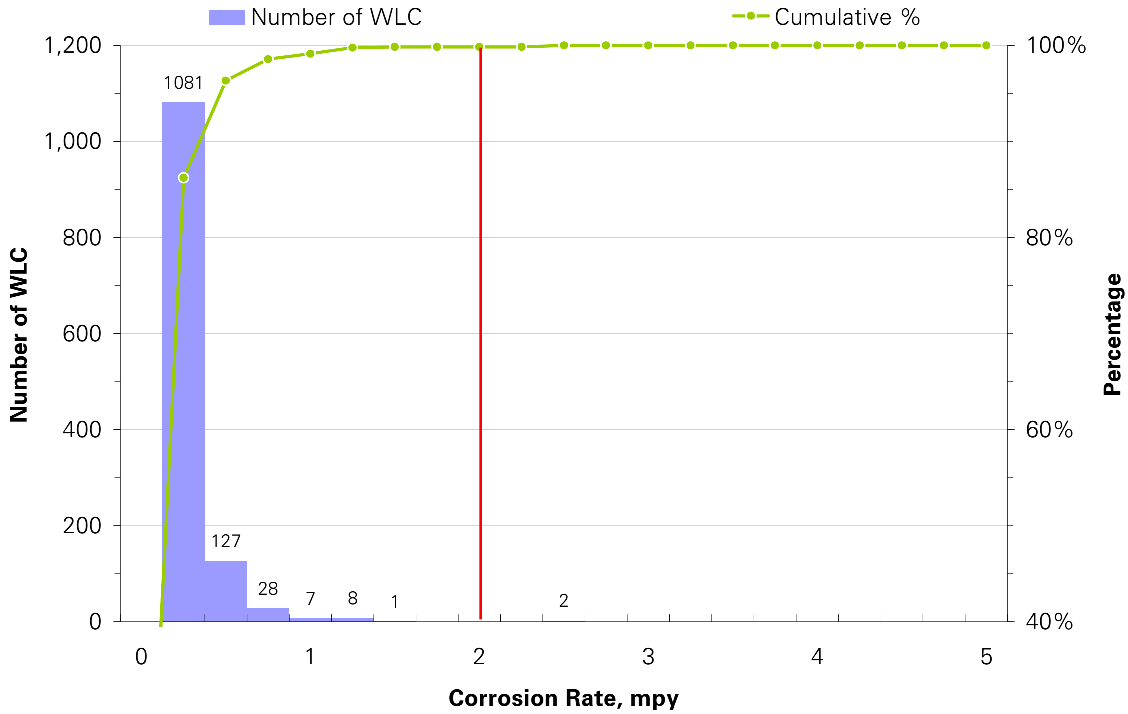
GPB Figure A.2 Flow Line Oil Service Corrosion Rate Trend

GPB Figure A.3 shows the correlation between average corrosion rate and the percentage of weight loss coupons meeting the 2 mpy target. As might be expected, there is a strong correlation between these two metrics. The average corrosion rate metric has the advantage of showing the overall performance trend for the system that would otherwise be lost when only looking at the exceptions >2 mpy. The value of exceptions is certainly not overlooked however, and all WLC corrosion rate exceptions are validated and addressed as needed.



GPB Figure A.3 Correlation between Flow Line Corrosion Rate and Percentage Conformance

GPB Figure A.4 shows the distribution of corrosion rates for WLC in flow line oil service. Only two WLC in flow line oil service exhibited general corrosion rates above the 2 mpy target; the highest being 2.4 mpy. None of the coupons in flow line oil service exceeded the pitting rate target of 20 mpy. Results from coupon analysis are reviewed on a regular basis as new data is received. Corrosion rate exceptions are investigated and inhibitor increases or other mitigation steps may be implemented according to established protocols. Two corrosion inhibitor increases were performed based on flow line WLC exceptions. Refer to Section D.1.5 for details and corrective actions for WLC exceptions.



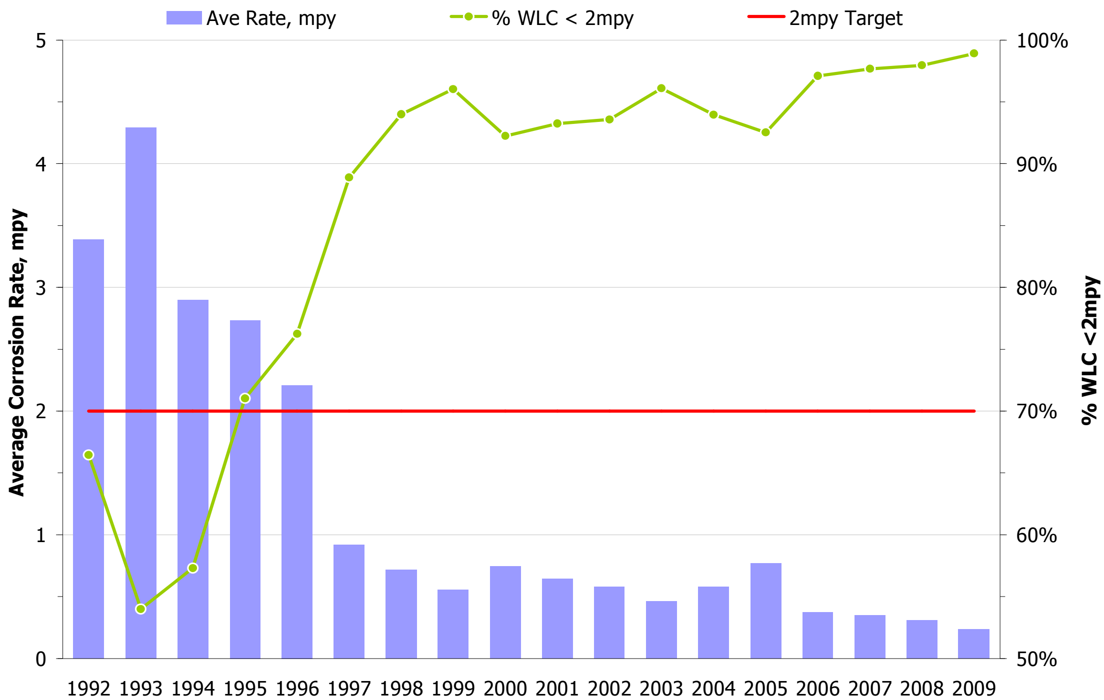
GPB Figure A.4 Flow Line Oil Service WLC Histogram

Section A.1.1.3 Well Line Coupons

The trends of the well lines are similar to those of the cross-country 3-phase oil flow lines, with both showing a long-term improvement in the level of corrosion control.

Continuous improvement in corrosion control for the well lines is demonstrated by a number of metrics. On average, about 5,500 WLC have been analyzed each year since 1992, representing the significant effort directed toward internal corrosion management of well lines. From 1993 to 1997, the average WLC corrosion rate decreased 79% (from >4 mpy to <1 mpy) as a direct result of continuous and batch inhibitor additions to the well lines. Since 1998, the application of corrosion inhibitor has sustained the average corrosion rate of well line coupons to below 1 mpy. A slight decrease in performance from 2003 to 2005 was largely due to chemical deployment problems which have been discussed in previous reports. In 2009, 99% of the well line coupons were below the 2 mpy general corrosion target and only 0.2% of the coupons exhibited a pit rate >20 mpy. The average corrosion rate for weight loss coupons in 3-phase well lines has decreased each year since 2005 and has been below the 2 mpy target every year since 1997. The WLC results indicate that mitigation performance for the well lines is largely successful. Opportunities for continued progress can be focused on the well lines represented by less than 1% of the WLC data.

GPB Figure A.5 shows the average corrosion rate and percentage of WLC ≤2 mpy for well line WLC since 1992.



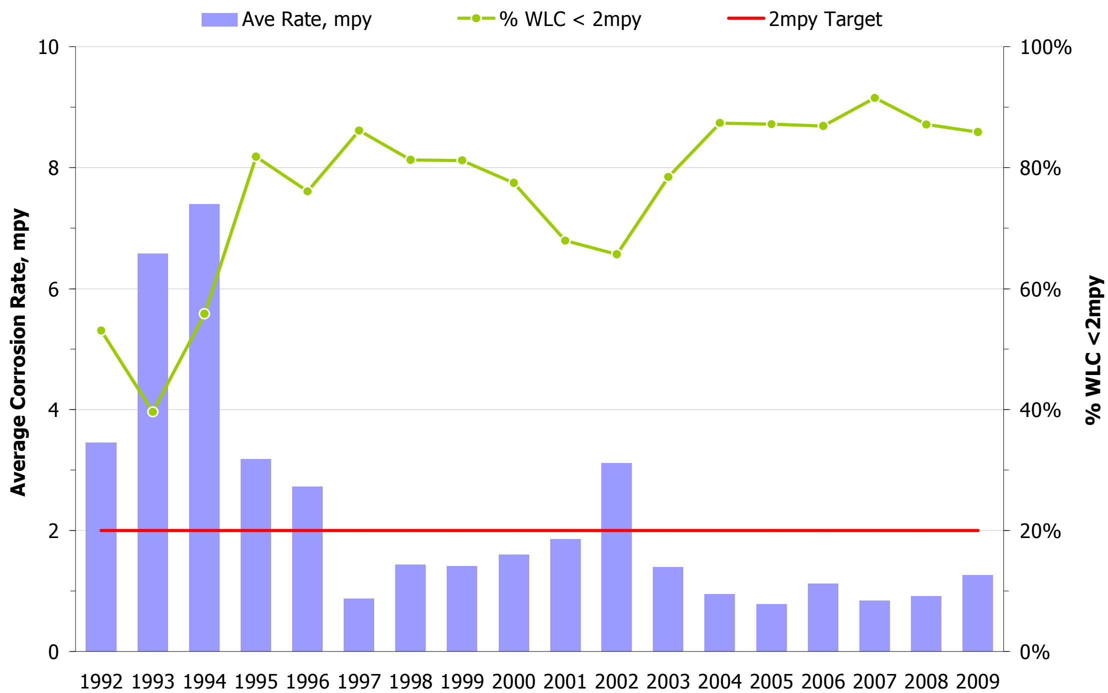
GPB Figure A.5 Well Line Oil Service Corrosion Rate Trend

Section A.1.2 Water Injection Systems

The water injection system at GPB handles produced water from the primary processing/separation facilities and seawater extracted from the Beaufort Sea and processed through the Seawater Treatment Plant (STP). For 2009, the average daily seawater injection volume was 590 Mbwpd.

Section A.1.2.1 Water Injection System Flow Lines

GPB Figure A.6 is a summary of aggregate data for produced water and seawater flow lines. The average WLC corrosion rate for produced water and seawater flow lines in 2009 was 1.3 mpy which is comparable to the performance of recent years but slightly higher than the average corrosion rate in 2008. The average pitting corrosion rate for WLC in the same PW and SW flow lines was 1.7 mpy and 99% of the coupons were below the 20 mpy target pitting rate.

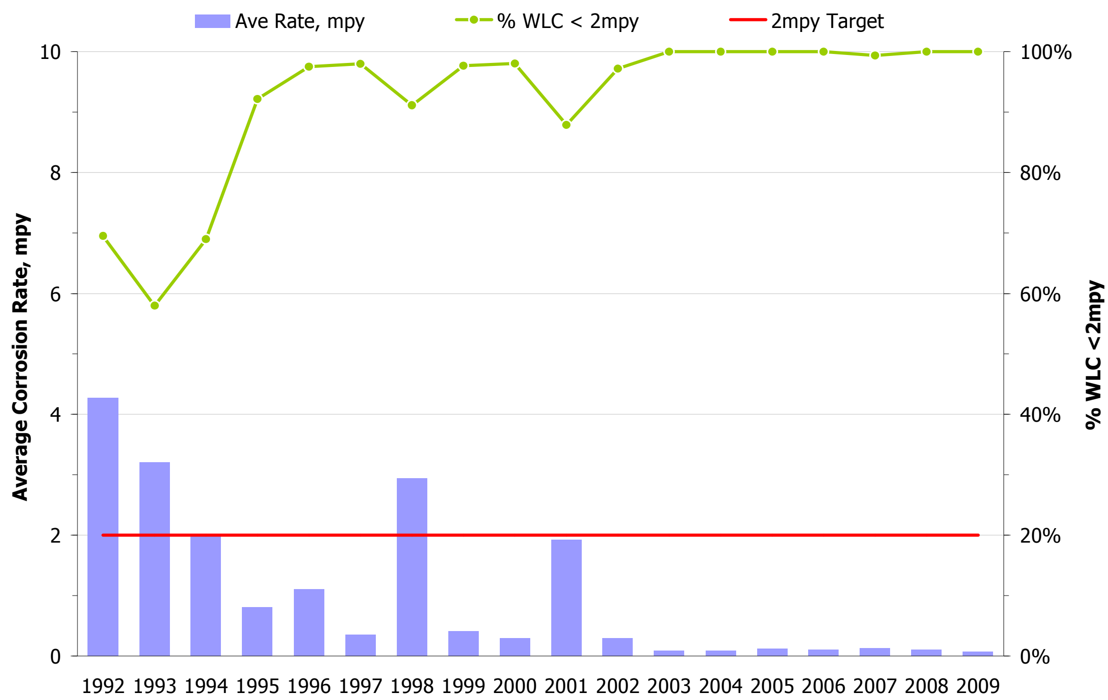


GPB Figure A.6 Flow Line PW/SW Service Corrosion Rate Trend

Section A.1.2.2 Produced Water Injection Well Lines

There are a number of corrosion mechanisms of concern in the produced water (PW) injection system. Pertinent mechanisms include CO_2 corrosion, differential concentration effects due to high levels of particulates in the water, and microbiologically influenced corrosion (MIC). The particulates consist primarily of residual hydrocarbons remaining after the separation process, entrained production chemicals, and iron sulfides.

GPB Figure A.7 and GPB Figure A.8 summarize the historical corrosion rate data for produced water well lines. The data show general corrosion rates in the produced water system have fallen as the level of inhibition in the 3-phase system was increased and after supplemental produced water corrosion inhibitor injection was initiated.

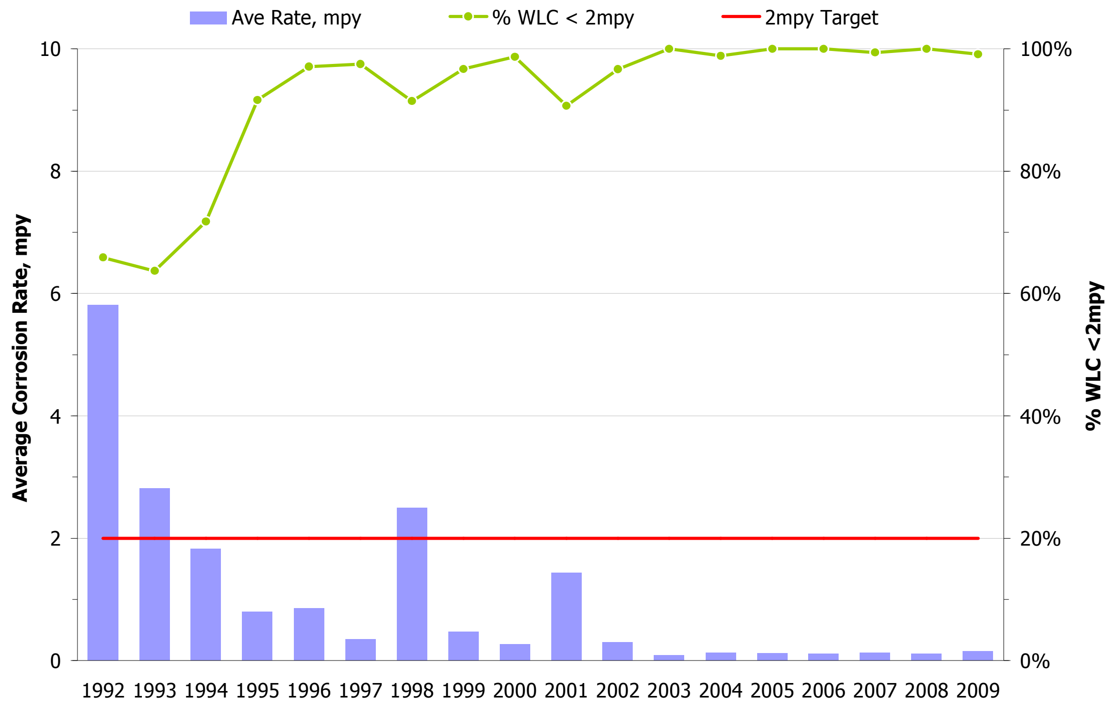


GPB Figure A.7 Corrosion Rate Trend for 100% PW System

GPB Figure A.7 shows the WLC general corrosion rate trend for 100% produced water service. The average corrosion rates remained at <0.1 mpy and 100% of the WLC in produced water service exhibited general corrosion rates less than 2 mpy. The average pitting corrosion rate for WLC in produced water service was 0.46 mpy and 100% of the coupons were below the 20 mpy target pitting rate.

For coupons exposed to majority produced water service, GPB Figure A.8 shows that corrosion rate trends are similar to those for 100% produced water service. While the results continue to be encouraging for both 100% PW and majority PW service, the statistical limitations of weight loss coupons relative to detecting underdeposit corrosion is recognized. The data set continues to increase for the PW system and as more inspection data becomes available the results of the WLC program will continue to be validated. New monitoring technology is also being evaluated for the PW system.

The overall improvement in the PW monitoring data since 2001 to date can be attributed to three primary factors. First, a change in the continuous corrosion inhibitor in the 3-phase system in 2002 provided more favorable partitioning characteristics to the water phase than the prior product. This change had the effect of increasing the levels of corrosion inhibitor carried from the upstream 3-phase system into the produced water distribution network. The second contributor is the increase in field-wide average concentration of corrosion inhibitor over time. The third contribution is the continuation of corrosion mitigation programs specific to the PW system that started in 2002. The programs include supplemental continuous inhibitor injection in the PW system at all GPB production facilities except Lisburne.



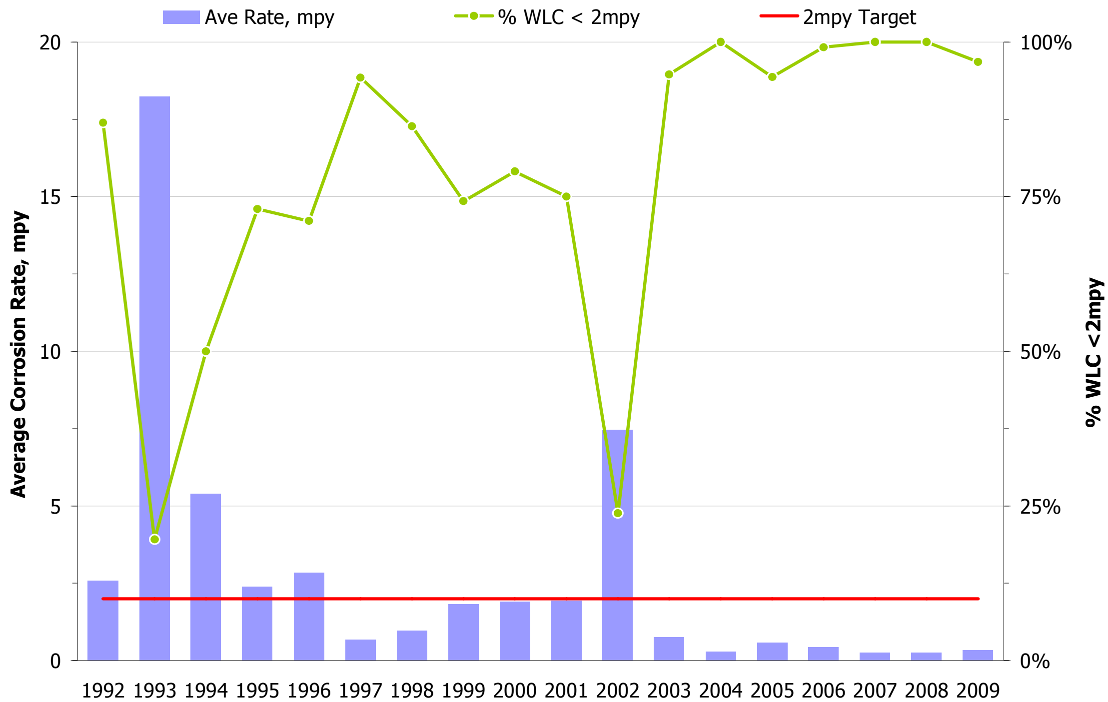
GPB Figure A.8 Corrosion Rate Trend for Majority PW System

Section A.1.2.3 Seawater Injection Well Lines

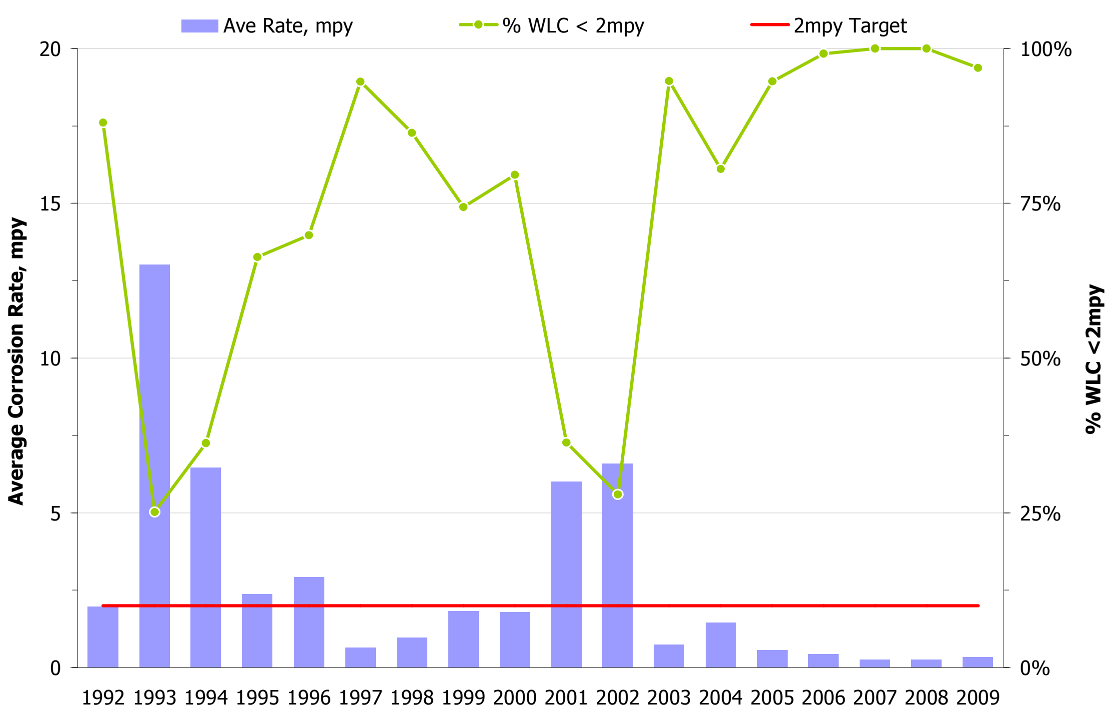
The main corrosion mechanisms in the seawater (SW) injection systems are,

- Dissolved oxygen (DO) corrosion – This mechanism is mitigated by processing the seawater to remove the oxygen. Initial DO removal is achieved mechanically by vacuum stripping, which is then followed by chemical oxygen scavenging.
- Microbiologically Influenced Corrosion (MIC) – MIC can result from the activities of bacteria and archaea, and is mitigated by batch treatment with biocide after the seawater is processed to remove DO.

As with the PW system, the SW system data is presented as both 100% and majority service for the well line WLC data. GPB Figure A.9 and GPB Figure A.10 show the corrosion rate trends for WLC in 100% SW service and majority SW service, respectively. For 100% SW service, the improvement in average corrosion rate since 2002 was the result of implementing corrective actions outlined in previous reports. Ninety-seven percent of WLC in 100% SW service and majority SW service were below the 2 mpy target. The average pitting corrosion rates for WLC in 100% seawater and majority seawater service are also well below the 20 mpy target maximum (0.65 and 0.67 mpy respectively). It is recognized that weight loss coupons may not be statistically representative of isolated MIC mechanisms and improved means of monitoring continue to be explored.



GPB Figure A.9 Corrosion Rate Trend for 100% Seawater System



GPB Figure A.10 Corrosion Rate Trend for Majority SW System

GPB Table A.2 summarizes historical changes in the biocide treatment program for the SW system. In 2008, a recommendation was made to batch treat with biocide twice weekly, however execution of the new treatment schedule did not occur until 2009 due to chemical storage tank availability and STP turnarounds.

From	To	ppm	Interval days	Product
Jan-97	Jul-97	750	7	Glutaraldehyde
Jul-97	Feb-00	750	14	Glutaraldehyde
Feb-00	Aug-01	450	14	Glutaraldehyde/quaternary amine blend
Aug-01	Jul-02	500	14	Glutaraldehyde/quaternary amine blend
Jul-02	Dec-02	500	7	Glutaraldehyde/quaternary amine blend
Dec-02	Mar-03	500	7	Glutaraldehyde/quaternary amine blend
Mar-03	Dec-03	750	7	Glutaraldehyde/quaternary amine blend
Dec-03	Oct-04	750	7	Glutaraldehyde
Oct-04	Apr-08	750	7	Glutaraldehyde/quaternary amine blend
May-09	Present	1,000	3.5	Glutaraldehyde/quaternary amine blend

GPB Table A.2 Biocide Treatment Concentration and Interval

In 2008, the oxygen scavenger injection system at STP was upgraded, improving the ability to control scavenger rates to each deaerator and monitor dissolved oxygen levels at the outlet of each deaerator. These upgrades will help control water quality from STP and continue to improve the control of internal corrosion.

In summary, the corrosion monitoring data suggest that improvements in corrosion control continue in the seawater system. As with the produced water system, the monitoring data set continues to grow and when combined with inspection results, confidence in the data will increase.

Section A.1.3 Electrical Resistance Probes

Electrical resistance (ER) probes are installed in various locations to monitor corrosion rates in flow lines throughout GPB. As compared to weight loss coupons which provide corrosion rate data for exposures over a period of months, ER probes can provide information about corrosion rates that occur over a period of hours. ER probes measure a change in resistance due to material loss from corrosion and the measurements are converted to corrosion rates in mils per year. ER probes are equipped with remote data collectors (RDC), which measure and record the metal loss data every 4 hours. This provides an adequate number of data points to assess corrosion rates while maximizing battery life in the units.

The typical ER probe used is a model T-10 that has a sensing element with 5 mils (0.005") of usable metal thickness. Probes are replaced if they are damaged, unresponsive, or if anomalous data is observed.

ER probes are located on both the upstream (well pad) end and downstream (gathering center) end of flow lines located on the west side of GPB. On the east side, probes are only located on the downstream (flow station) end of flow lines.

For the electrical resistance (ER) probes, the number of active locations in GPB flow lines is given in GPB Table A.3 The number of probes in service increased in 2009, representing continuous improvements in monitoring capabilities.

Year	Total Probe Locations
2001	83
2002	82
2003	85
2004	87
2005	87
2006	87
2007	87
2008	90
2009	108

GPB Table A.3 Active ER Probe Locations

ER probe data is collected in the field and uploaded to the corrosion and inspection database once per week. The target ER probe corrosion rate is 2 mpy. Each week any ER probe with a seven day average corrosion rate greater than 2 mpy is evaluated to determine data validity. If a legitimate increase in corrosion rate is verified based on the probe data analysis and other supporting operational data, an appropriate response is determined and the probe is considered 'actioned'. The action can be a corrosion inhibitor increase, however other types of mitigation may also be recommended.

GPB Table A.4 shows the number of weekly ER probe readings where corrosion rates were greater than target, as compared to the number of weekly ER probe readings on which action was taken, dating back to 2001. On three occasions where probe corrosion rate readings were greater than 2 mpy, corrosion inhibitor rate increase actions were recommended.

Year	Average % ≤ 2 mpy	No. ER Probe > 2 mpy	No. ER Probes 'Actioned'
2001	97%	193	6
2002	97%	137	6
2003	96%[6]	138	21
2004	92%	315	59
2005	88%	241	11
2006	86%	232	7
2007	93%	270	2
2008	80%	286	3
2009	80%	291	3

GPB Table A.4 Number of ER Probe Readings >2 mpy and 'Actioned'[7]

Each year there are a number of probes that report suspect metal loss data as a result of fluid flow and/or temperature fluctuations. These fluctuations are regularly investigated to validate whether the corrosion rate for the ER probe actually exceeds the 2 mpy target.

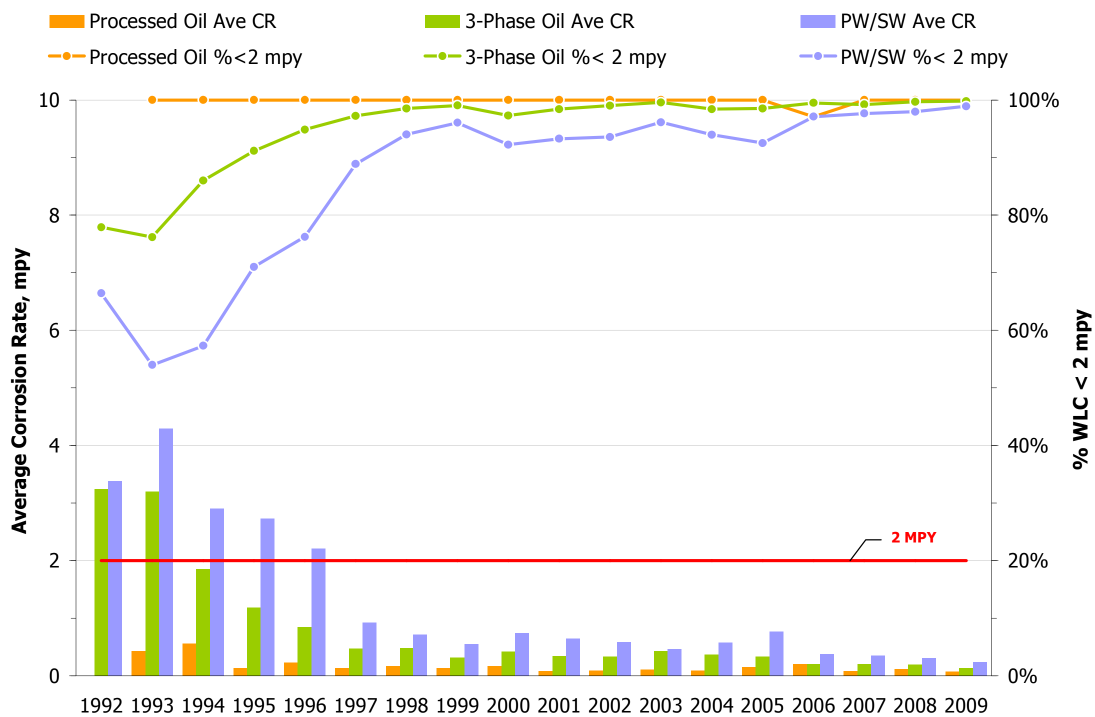
Section D.1.5 shows the corrective mitigation actions taken as a result of ER probe readings exceeding target. Appendix 3.3.1 describes by example, the methodology by which corrosion inhibitor concentration is increased as a result of ER probe monitoring results.

Section A.1.4 1992 to Date Summary by System

This section provides a comparative summary of WLC data collected since 1992 for the major systems at GPB. GPB Figure A.11 shows the WLC corrosion rate and corrosion target conformance since 1992. The average corrosion rate in the 3-phase production system has remained low since 2002 and illustrates a high level of corrosion control. The reasons for improvement in the water injection system performance were provided in Section A.1.2.

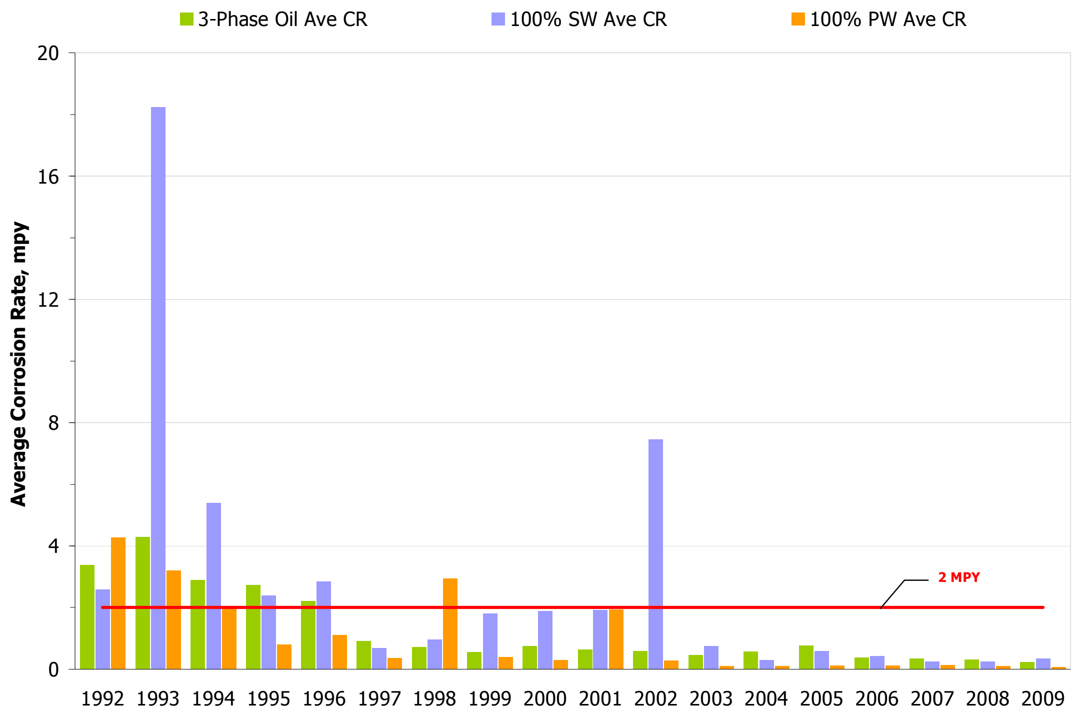
[6] Incorrectly reported as 93% in 2003 Report

[7] Values updated in 2009 report to accurately reflect less than or equal to 2 mpy

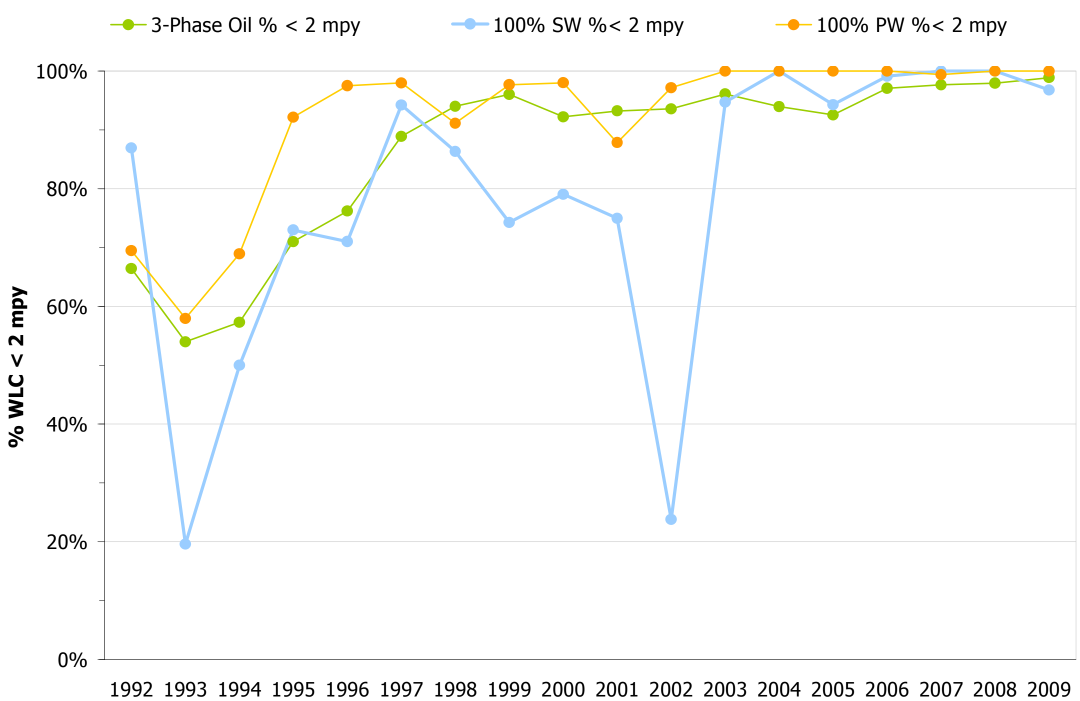


GPB Figure A.11 Flow Line Corrosion Coupon Summary by Equipment and Service

GPB Figure A.12 shows the corrosion rate and GPB Figure A.13 shows WLC corrosion conformance for well lines. Corrosion rates in the well line 3-phase system have remained low since 2000. The produced water and seawater well lines' corrosion performance has shown gradual improvement since 2002.



GPB Figure A.12 Well Line WLC Average Corrosion Rate Summary by Equipment and Service

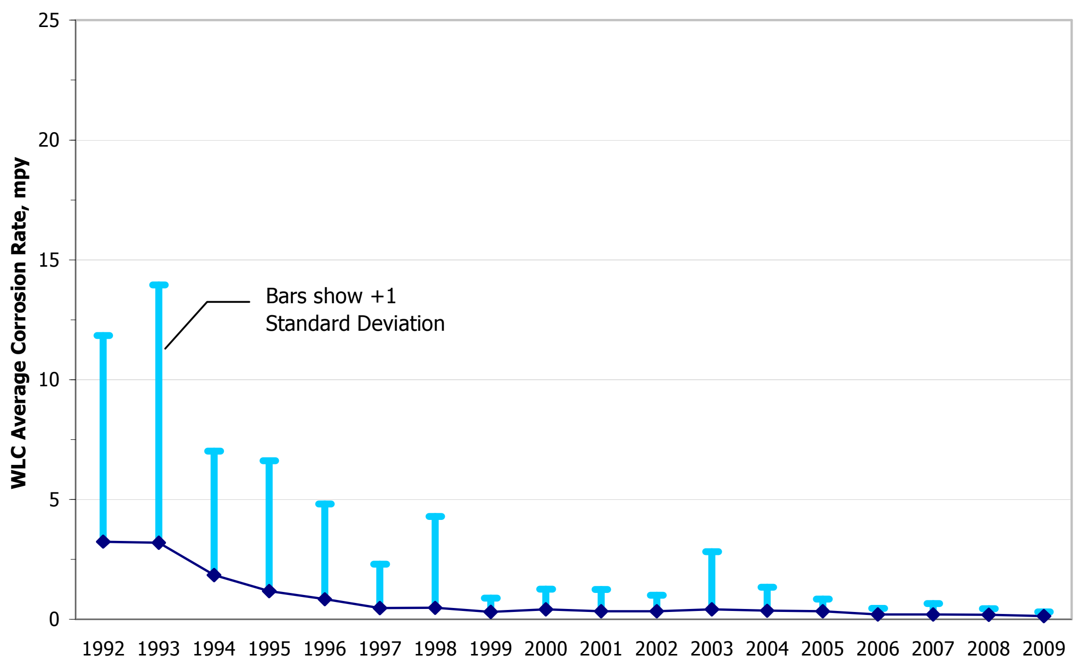


GPB Figure A.13 Well line WLC %<2 mpy Summary by Equipment and Service

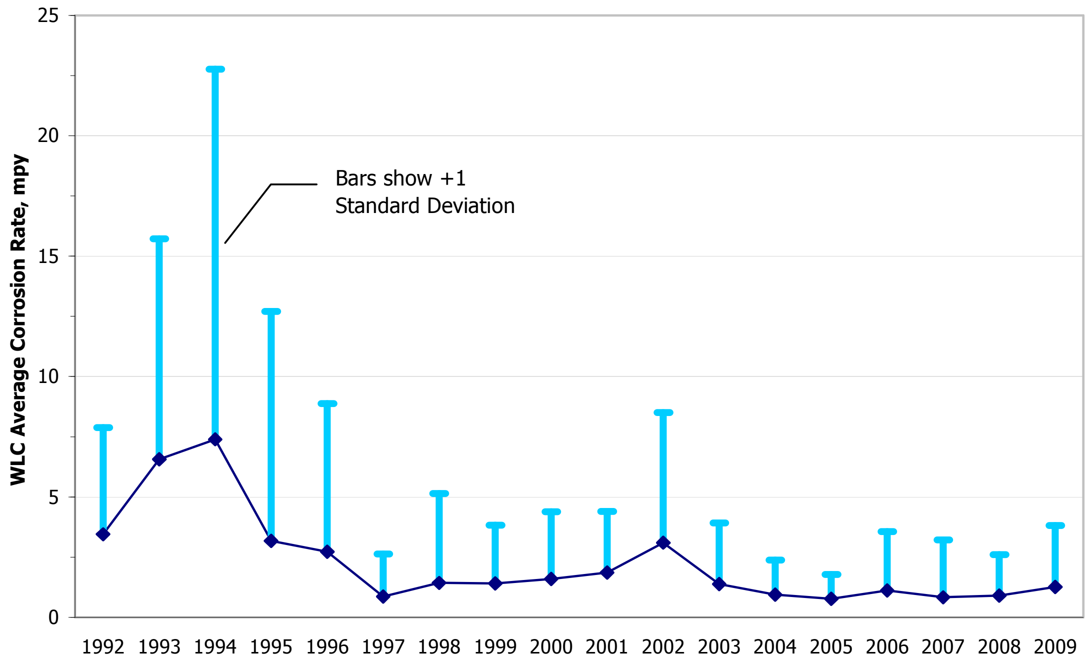
While the average WLC corrosion rate for each service type is a useful metric, another consideration is the range of corrosion rate values observed. One way of comparing the relative range of corrosion rates to the average corrosion rate is to calculate a standard deviation for the data set. GPB Figure A.14 through GPB Figure A.19 show the average WLC corrosion rate and corresponding standard deviation for each service type since 1992. Most significantly, the trend observed in all systems is a declining standard deviation (concurrent with the declining average CR) since the early days of the program. This observation increases confidence in the declining CR values and supports other data that suggest mitigation activities are effective.

Another metric of corrosion management performance identified through the WLC program is pitting rate. In 2009, 100% of the WLCs in all service types except PW/SW flow lines and majority PW well lines (which were both 99%) were below the target maximum pitting rate of 20 mpy. These WLC metrics continue to demonstrate successful performance of corrosion mitigation efforts.

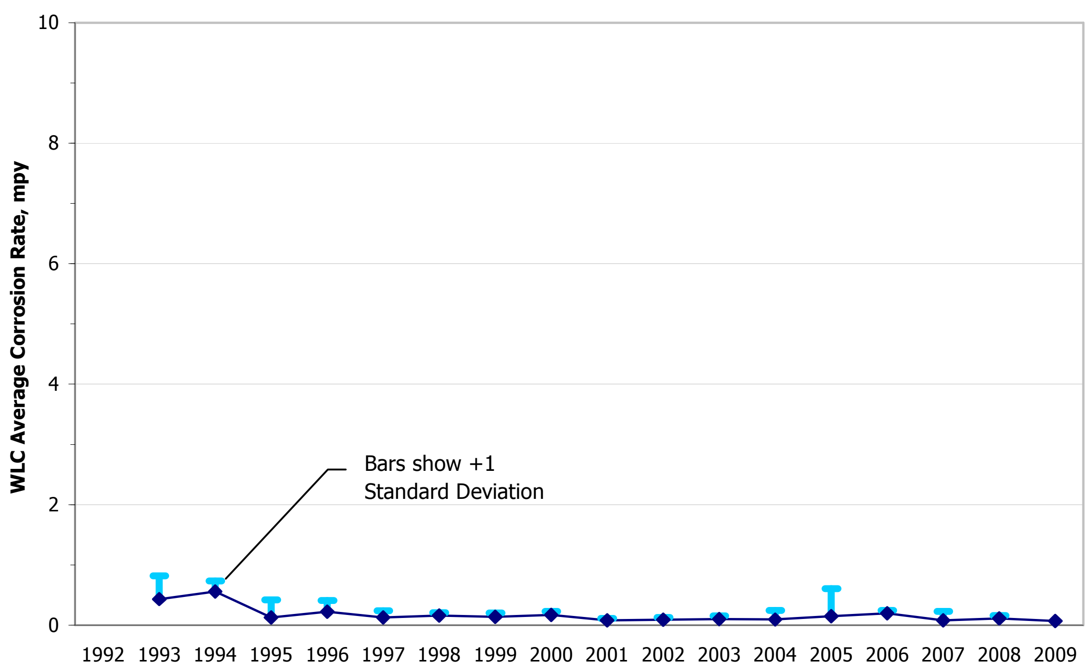
In light of the corrosion history of the flow lines and well lines presented here, continued improvement in the control of corrosion is clearly evident. GPB Table A.5 presents historical WLC corrosion rate data for the major GPB services since 1992. Pitting rate data for the same services and time period is shown in GPB Table A.6.



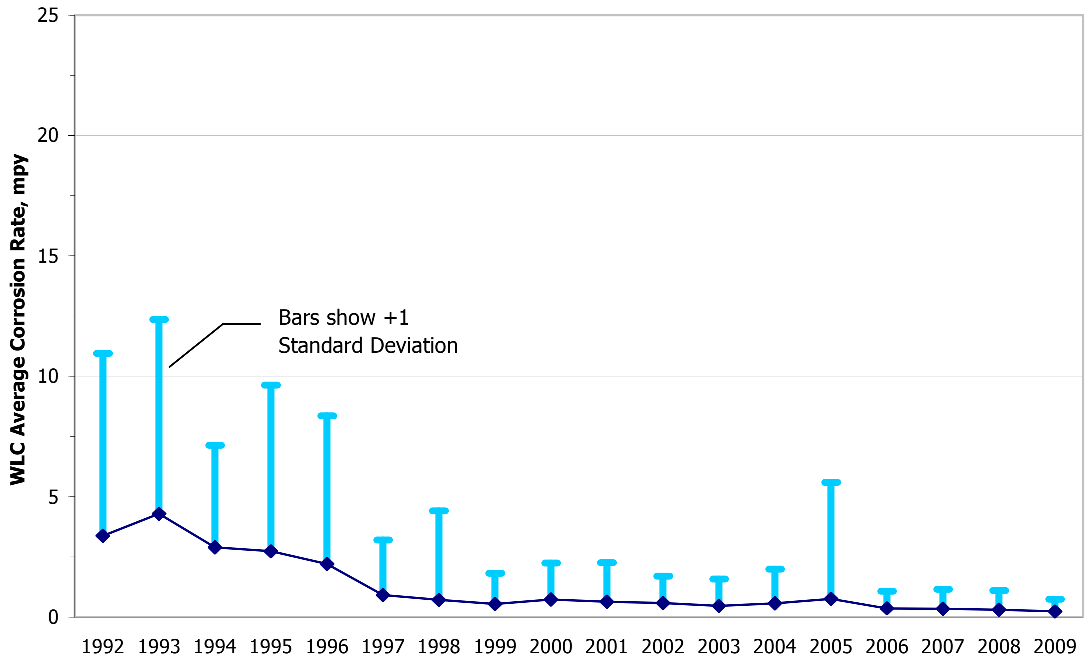
GPB Figure A.14 WLC Corrosion Rate and Standard Deviation for 3 Phase Oil Flow Lines.



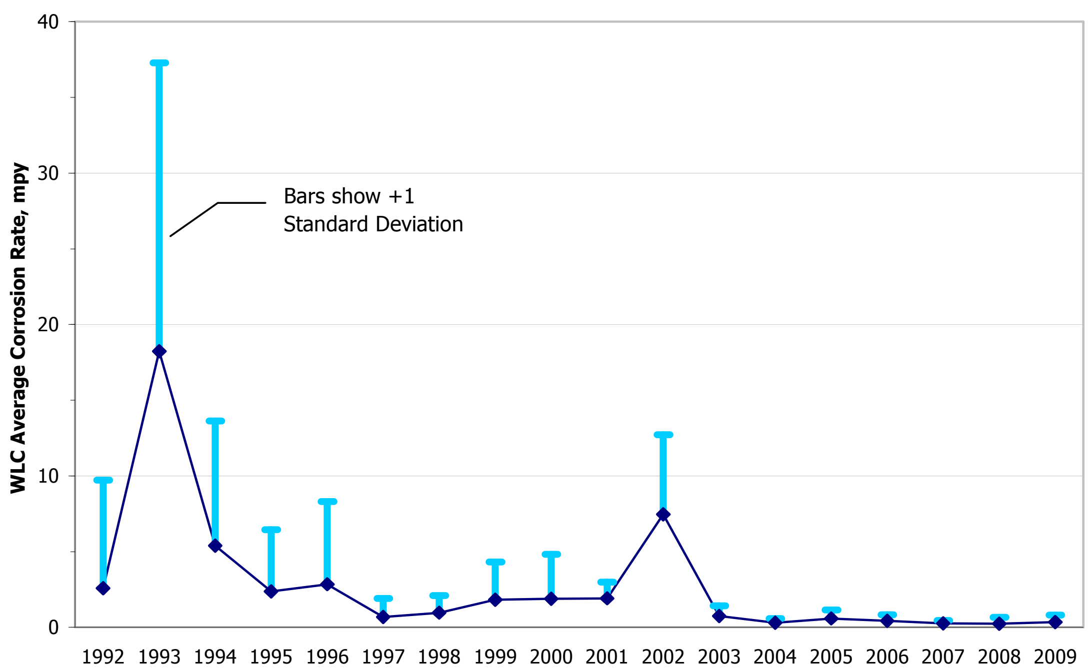
GPB Figure A.15 WLC Corrosion Rate and Standard Deviation for PW/SW Flow Lines.



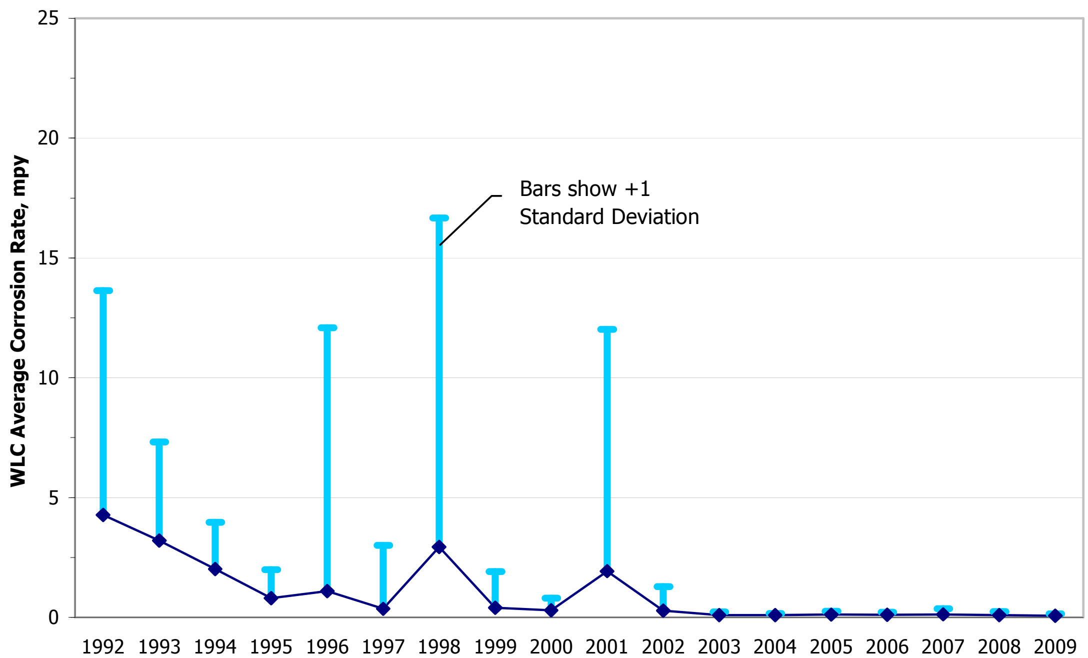
GPB Figure A.16 WLC Corrosion Rate and Standard Deviation, for Processed Oil Flow Lines.



GPB Figure A.17 WLC Corrosion Rate and Standard Deviation, for 3 Phase Oil Well Lines.



GPB Figure A.18 WLC Corrosion Rate and Standard Deviation, for 100% SW Well Lines.



GPB Figure A.19 WLC Corrosion Rate and Standard Deviation, for 100% PW Well lines.

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BU	Equip	Service	Metric	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
GPB	FL	OIL	WLC	746	916	958	1,379	1,514	1,563	1,447	1,475	1,409	1,262	1,316	1,314	1,240	1,297	1,168	1,301	1,267	1,066
GPB	FL	OIL	Ave CR	3.24	3.20	1.85	1.18	0.84	0.47	0.48	0.31	0.42	0.34	0.33	0.42	0.36	0.33	0.20	0.20	0.19	0.14
GPB	FL	OIL	SD CR	8.60	10.75	5.17	5.44	3.98	1.84	3.81	0.57	0.84	0.91	0.68	2.40	0.99	0.51	0.26	0.46	0.26	0.17
GPB	FL	OIL	WLC < 2	581	698	824	1,257	1,436	1,520	1,426	1,461	1,371	1,242	1,303	1,308	1,220	1,278	1,162	1,291	1,263	1,064
GPB	FL	OIL	% WLC < 2mpy	78%	76%	86%	91%	95%	97%	99%	99%	97%	98%	99%	100%	98%	99%	99%	99%	100%	100%
GPB	FL	PW/SW	WLC	81	106	154	198	184	195	171	181	160	131	137	144	119	117	122	118	101	78
GPB	FL	PW/SW	Ave CR	3.45	6.58	7.40	3.18	2.73	0.87	1.44	1.41	1.60	1.86	3.11	1.39	0.95	0.78	1.12	0.84	0.91	1.27
GPB	FL	PW/SW	SD CR	4.43	9.13	15.37	9.52	6.15	1.77	3.72	2.42	2.78	2.54	5.39	2.52	1.43	1.01	2.44	2.38	1.70	2.54
GPB	FL	PW/SW	WLC < 2	43	42	86	162	140	168	139	147	124	89	90	113	104	102	106	108	88	67
GPB	FL	PW/SW	%<2mpy	53%	40%	56%	82%	76%	86%	81%	81%	78%	68%	66%	78%	87%	87%	87%	92%	87%	86%
GPB	FL	PO	WLC		16	23	24	34	44	32	34	36	22	28	44	38	42	34	35	31	25
GPB	FL	PO	Ave CR		0.43	0.56	0.13	0.23	0.13	0.16	0.14	0.17	0.08	0.09	0.11	0.09	0.15	0.20	0.08	0.12	0.07
GPB	FL	PO	SD CR		0.41	0.39	0.17	0.29	0.19	0.11	0.05	0.07	0.06	0.03	0.04	0.05	0.15	0.45	0.05	0.15	0.05
GPB	FL	PO	WLC < 2		16	23	24	34	44	32	34	36	22	28	44	38	42	33	35	31	25
GPB	FL	PO	% WLC < 2mpy		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	97%	100%	100%	100%
GPB	WL	OIL	WLC	6,726	5,580	4,931	5,206	6,531	6,741	6,384	6,189	6,241	4,849	5,276	5,572	5,225	5,423	5,368	5,574	5,033	4,319
GPB	WL	OIL	Ave CR	3.39	4.29	2.90	2.73	2.21	0.92	0.72	0.56	0.75	0.64	0.58	0.46	0.58	0.77	0.37	0.35	0.31	0.24
GPB	WL	OIL	SD CR	7.57	8.06	4.24	6.90	6.15	2.29	3.71	1.27	1.50	1.61	1.13	1.13	1.41	4.82	0.72	0.82	0.81	0.51
GPB	WL	OIL	WLC < 2	4,469	3,013	2,826	3,697	4,979	5,992	6,001	5,944	5,757	4,522	4,937	5,355	4,910	5,018	5,212	5,444	4,930	4,272
GPB	WL	OIL	% WLC < 2mpy	66%	54%	57%	71%	76%	89%	94%	96%	92%	93%	94%	96%	94%	93%	97%	98%	98%	99%
GPB	WL	Majority PW	WLC	487	474	642	829	966	1,045	938	730	696	656	451	416	450	426	390	346	365	230
GPB	WL	Majority PW	Ave CR	5.81	2.82	1.83	0.80	0.86	0.35	2.50	0.47	0.27	1.44	0.30	0.09	0.13	0.12	0.11	0.13	0.11	0.15
GPB	WL	Majority PW	SD CR	13.21	3.93	1.78	1.19	8.72	2.29	12.22	1.66	0.43	8.57	0.89	0.13	0.31	0.14	0.12	0.22	0.17	0.72
GPB	WL	Majority PW	WLC < 2	321	302	461	760	938	1,019	858	706	687	595	436	416	445	426	390	344	365	228
GPB	WL	Majority PW	% WLC < 2mpy	66%	64%	72%	92%	97%	98%	91%	97%	99%	91%	97%	100%	99%	100%	100%	99%	100%	99%
GPB	WL	100% PW	WLC	246	264	274	485	604	697	711	518	458	470	321	346	364	370	350	324	341	206
GPB	WL	100% PW	Ave CR	4.27	3.21	2.02	0.81	1.10	0.36	2.94	0.41	0.30	1.93	0.29	0.09	0.09	0.12	0.11	0.13	0.10	0.07
GPB	WL	100% PW	SD CR	9.37	4.11	1.95	1.19	10.98	2.66	13.73	1.51	0.51	10.09	0.99	0.13	0.08	0.14	0.11	0.23	0.14	0.08
GPB	WL	100% PW	WLC < 2	171	153	189	447	589	683	648	506	449	413	312	346	364	370	350	322	341	206
GPB	WL	100% PW	% WLC < 2mpy	70%	58%	69%	92%	98%	98%	91%	98%	98%	88%	97%	100%	100%	100%	100%	99%	100%	100%
GPB	WL	Majority SW	WLC	434	410	364	279	146	56	44	82	98	44	25	19	36	94	123	120	70	64
GPB	WL	Majority SW	Ave CR	1.97	13.02	6.45	2.37	2.92	0.65	0.96	1.82	1.78	6.01	6.58	0.74	1.45	0.56	0.44	0.26	0.25	0.33
GPB	WL	Majority SW	SD CR	5.48	16.14	7.65	3.63	4.95	1.20	1.14	2.36	2.77	6.88	5.27	0.68	2.65	0.54	0.42	0.20	0.41	0.48
GPB	WL	Majority SW	WLC < 2	382	103	132	185	102	53	38	61	78	16	7	18	29	89	122	120	70	62
GPB	WL	Majority SW	% WLC < 2mpy	88%	25%	36%	66%	70%	95%	86%	74%	80%	36%	28%	95%	81%	95%	99%	100%	100%	97%
GPB	WL	100% SW	WLC	184	194	158	163	76	52	44	70	86	16	21	19	12	88	115	108	64	62
GPB	WL	100% SW	Ave CR	2.59	18.24	5.39	2.38	2.84	0.68	0.96	1.82	1.89	1.92	7.46	0.74	0.30	0.59	0.43	0.26	0.25	0.33
GPB	WL	100% SW	SD CR	7.13	19.04	8.25	4.05	5.46	1.24	1.14	2.50	2.93	1.07	5.28	0.68	0.27	0.55	0.41	0.20	0.43	0.48
GPB	WL	100% SW	WLC < 2	160	38	79	119	54	49	38	52	68	12	5	18	12	83	114	108	64	60
GPB	WL	100% SW	% WLC < 2mpy	87%	20%	50%	73%	71%	94%	86%	74%	79%	75%	24%	95%	100%	94%	99%	100%	100%	97%

GPB Table A.5 Flow and Well Line General Corrosion Rate Data Summary

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BU	Equip	Service	Metric	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
GPB	FL	OIL	WLC	746	916	958	1,379	1,514	1,563	1,447	1,475	1,409	1,262	1,316	1,314	1,240	1,297	1,168	1,301	1,267	1,066
GPB	FL	OIL	Ave P CR	6.69	5.80	4.15	9.06	7.66	6.74	2.91	1.67	1.89	1.29	0.73	0.65	1.24	0.42	0.04	0.05	0.05	0.08
GPB	FL	OIL	SD P CR	21.08	15.73	13.52	23.14	14.97	13.70	6.66	6.24	7.77	10.71	3.89	8.35	5.90	2.60	0.72	0.78	0.86	1.18
GPB	FL	OIL	P WLC < 20	661	834	909	1,260	1,425	1,510	1,422	1,452	1,377	1,247	1,296	1,312	1,225	1,293	1,168	1,301	1,267	1,065
GPB	FL	OIL	% P WLC <20mpy	89%	91%	95%	91%	94%	97%	98%	98%	98%	99%	98%	100%	99%	100%	100%	100%	100%	100%
GPB	FL	PW/SW	WLC	81	106	154	198	184	195	171	181	160	131	137	144	119	117	122	118	101	78
GPB	FL	PW/SW	Ave P CR	8.53	15.83	17.28	17.03	14.40	15.26	11.36	5.31	6.36	9.37	13.12	7.07	3.04	2.57	4.54	1.44	1.83	1.73
GPB	FL	PW/SW	SD P CR	8.49	5.40	8.61	6.60	5.40	4.11	3.01	2.53	2.33	0.91	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00
GPB	FL	PW/SW	P WLC < 20	66	83	111	150	147	172	156	168	153	112	106	125	119	114	112	114	98	77
GPB	FL	PW/SW	% P WLC <20mpy	81%	78%	72%	76%	80%	88%	91%	93%	96%	85%	77%	87%	100%	97%	92%	97%	97%	99%
GPB	FL	PO	WLC		16	23	24	34	44	32	34	36	22	28	44	38	42	34	35	31	25
GPB	FL	PO	Ave P CR		0.50	0.70	1.88	2.56	3.73	2.19	1.26	1.44	1.05	0.77	0.32	0.66	0.00	1.12	0.00	0.00	0.00
GPB	FL	PO	SD P CR		1.15	2.48	3.42	4.64	4.31	5.65	2.43	3.49	3.47	3.92	2.11	2.83	0.00	3.66	0.00	0.00	0.00
GPB	FL	PO	P WLC < 20		16	23	24	34	44	31	34	36	22	26	44	38	42	34	35	31	25
GPB	FL	PO	% P WLC <20mpy		100%	100%	100%	100%	100%	97%	100%	100%	100%	93%	100%	100%	100%	100%	100%	100%	100%
GPB	WL	OIL	WLC	6,726	5,580	4,931	5,206	6,531	6,741	6,384	6,189	6,241	4,849	5,276	5,572	5,225	5,423	5,368	5,574	5,033	4,319
GPB	WL	OIL	Ave P CR	7.29	9.36	5.14	11.50	11.68	5.21	3.21	2.90	3.29	1.96	1.71	1.66	1.94	1.68	0.53	0.48	0.26	0.23
GPB	WL	OIL	SD P CR	22.46	24.28	14.13	32.30	28.57	14.66	9.98	9.30	10.14	6.43	5.62	5.33	5.78	5.71	2.64	3.95	1.95	2.05
GPB	WL	OIL	P WLC < 20	5,805	4,929	4,601	4,554	5,654	6,471	6,226	6,061	6,054	4,746	5,201	5,522	5,130	5,331	5,355	5,565	5,028	4,313
GPB	WL	OIL	% P WLC <20mpy	86%	88%	93%	87%	87%	96%	98%	98%	97%	98%	99%	99%	98%	98%	100%	100%	100%	100%
GPB	WL	Majority PW	WLC	487	474	642	829	966	1,045	938	730	696	656	451	416	450	426	390	346	365	230
GPB	WL	Majority PW	Ave P CR	36.11	23.59	16.00	20.18	15.10	9.69	21.15	8.99	4.67	6.72	2.94	1.05	1.87	1.24	1.14	1.27	0.88	0.80
GPB	WL	Majority PW	SD P CR	41.91	30.49	27.41	29.05	29.78	29.33	59.33	26.23	9.76	17.56	9.09	2.96	7.76	3.89	4.03	4.06	3.25	3.34
GPB	WL	Majority PW	P WLC < 20	225	281	485	574	792	941	780	664	667	576	438	415	447	424	385	342	363	228
GPB	WL	Majority PW	% P WLC <20mpy	46%	59%	76%	69%	82%	90%	83%	91%	96%	88%	97%	100%	99%	100%	99%	99%	99%	99%
GPB	WL	100% PW	WLC	246	264	274	485	604	697	711	518	458	470	321	346	364	370	350	324	341	206
GPB	WL	100% PW	Ave P CR	36.30	21.18	13.60	20.74	15.15	7.57	22.45	7.21	4.69	8.18	2.76	0.99	1.21	1.28	0.98	1.31	0.77	0.46
GPB	WL	100% PW	SD P CR	39.37	27.94	20.27	30.96	30.19	19.55	64.59	25.62	11.15	20.02	9.85	2.97	3.39	4.01	3.65	4.17	2.80	1.70
GPB	WL	100% PW	P WLC < 20	102	159	210	321	496	639	592	481	432	393	312	345	363	368	347	318	340	206
GPB	WL	100% PW	% P WLC < 20mpy	41%	60%	77%	66%	82%	92%	83%	93%	94%	84%	97%	100%	100%	99%	99%	98%	100%	100%
GPB	WL	Majority SW	WLC	434	410	364	279	146	56	44	82	98	44	25	19	36	94	123	120	70	64
GPB	WL	Majority SW	Ave P CR	4.74	17.32	9.26	10.85	15.08	1.50	1.55	5.62	6.61	18.80	29.33	9.11	12.86	2.11	2.94	0.70	0.61	0.63
GPB	WL	Majority SW	SD P CR	15.65	44.26	14.36	16.08	22.90	4.52	2.31	8.16	10.40	18.59	27.35	20.21	30.17	4.03	8.56	2.54	2.33	2.23
GPB	WL	Majority SW	P WLC < 20	404	320	315	233	109	55	44	80	92	24	15	16	32	94	119	120	70	64
GPB	WL	Majority SW	% P WLC < 20mpy	93%	78%	87%	84%	75%	98%	100%	98%	94%	55%	60%	84%	89%	100%	97%	100%	100%	100%
GPB	WL	100% SW	WLC	184	194	158	163	76	52	44	70	86	16	21	19	12	88	115	108	64	62
GPB	WL	100% SW	Ave P CR	5.19	13.31	7.35	8.52	9.63	0.54	1.55	5.24	5.57	9.13	31.62	9.11	9.17	2.01	2.11	0.50	0.67	0.65
GPB	WL	100% SW	SD P CR	18.94	18.79	12.39	13.75	19.92	2.18	2.31	8.49	6.38	7.30	29.49	20.21	21.36	4.03	6.29	2.16	2.43	2.26
GPB	WL	100% SW	P WLC < 20	172	157	141	140	62	52	44	68	82	14	12	16	10	88	113	108	64	62
GPB	WL	100% SW	% P WLC <20mpy	93%	81%	89%	86%	82%	100%	100%	97%	95%	88%	57%	84%	83%	100%	98%	100%	100%	100%

GPB Table A.6 Flow and Well Line Pitting Rate Data Summary

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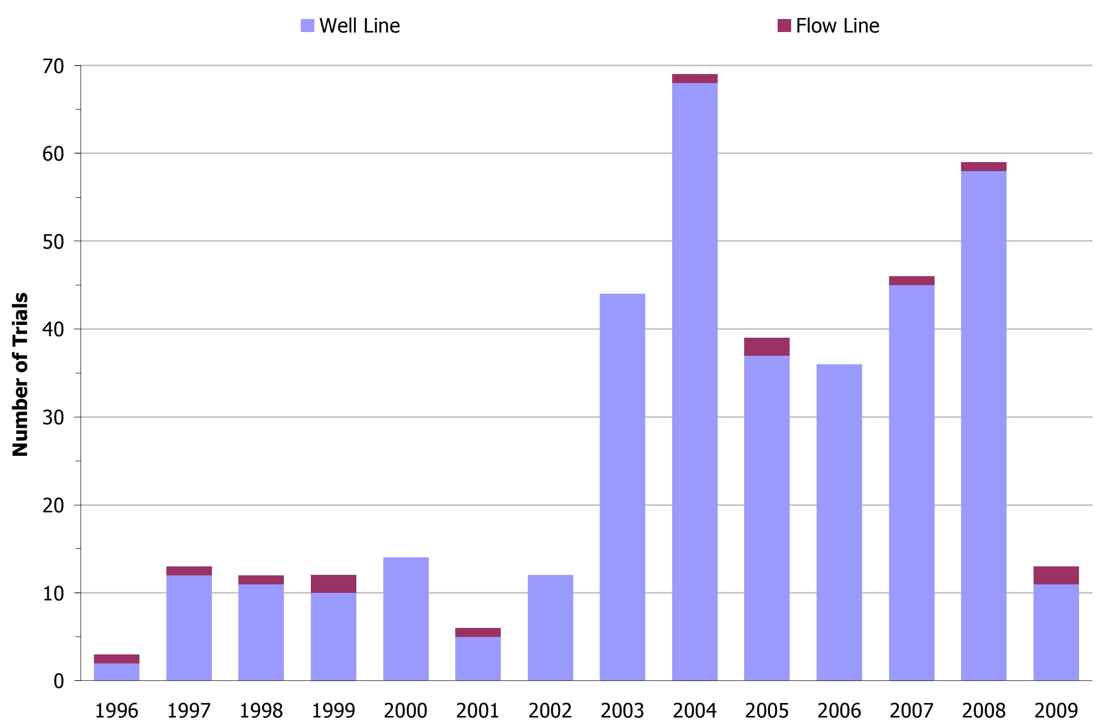
Section A.2 Corrosion Inhibition

Corrosion inhibition is an on-going process that encompasses a broad range of activities, from developing new corrosion inhibitors for improved performance, to the allocation of the optimal volumes of chemical for corrosion control. The following sections provide an update on chemical development, field wide chemical deployment, chemical usage and finally corrosion control.

Section A.2.1 3-Phase Corrosion Inhibitor Testing

GPB Figure A.20 summarizes the number of well line and flow line corrosion inhibitor tests that have been completed since 1996. The level of well line test activity increased beginning in 2003 due to a change in the screening protocol, which reduced the time required per test. The combined number of well line and flow line tests increased from 10-14 per year[8] to more than fifty-nine during 2008. The number of well line tests was lower this year because the corrosion inhibitor test skids are being upgraded to improve chemical metering. The test skids are expected to be completed and placed in service by mid-2010, allowing two test periods to be completed next year.



GPB Figure A.20 Number of Well Line and Flow line Tests

Section A.2.2 3-Phase Corrosion Inhibitor Deployment

The chemical development and testing program has been highly successful with 16 new products being developed for use in the continuous wellhead inhibition program

[8] The data prior to 2000 are incomplete and represents the test work completed on the heritage WOA only.

since 1995. All these changes represent a significant improvement in overall corrosion control performance.

GPB Table A.7 summarizes the changes in corrosion inhibitor products since 1995. The table does not include test products that did not make it to field-wide usage. In addition, the summary table does not include summer versions of products that differ only in pour point from the winter version shown in the table.

Supplier	Chemical	95	96	97	98	99	00	01	02	03	04	05	06	07	08	09
Nalco Exxon	EC1110A	■	■													
Nalco Exxon	EC1259			■	■											
Nalco Exxon	97VD129				■	■	■									
Nalco Exxon	98VD118				■	■	■	■								
ONDEO Nalco	99VD049					■	■	■								
ONDEO Nalco	01VD017							■								
ONDEO Nalco	01VD121							■	■	■	■		■	■	■	■
Nalco	DVE4D002											■				
Champion	RU205	■														
Champion	RU210	■	■	■												
Champion	RU223	■	■	■	■											
Champion	RU258			■												
Champion	RU271				■	■	■									
Champion	RU126A						■									
Champion	RU256[1]			■	■	■	■	■	■	■	■					
Champion	Cortron 2004-15[1]										■	■	■	■	■	■

[1] Used for the batch treatment of well lines while the remaining chemicals are all used for continuous application

GPB Table A.7 Summary of Chemical Deployment History in 3-Phase Service

Section A.2.3 3-Phase Corrosion Inhibitor Usage and Concentration

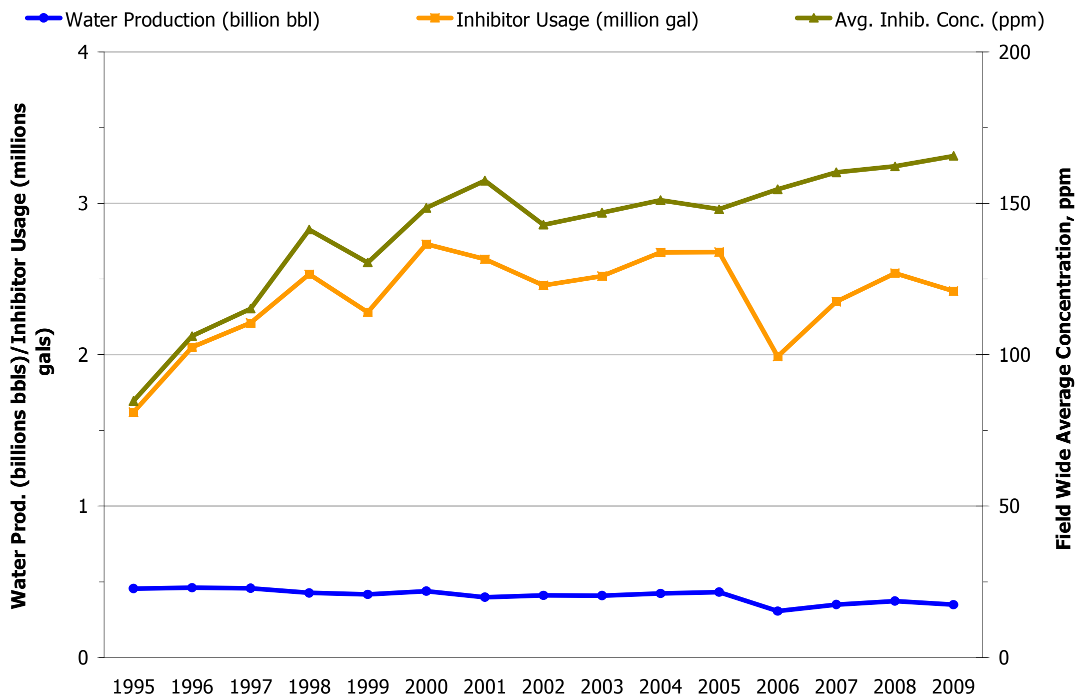
The concentration of inhibitor in the water phase reflects the potential effectiveness of the chemical used to control corrosion. Concentration values alone however, can be misleading as different types of corrosion inhibitors used can vary from year to year (GPB Table A.7). As more effective chemicals are developed, the applied volumes and concentrations will change depending on the individual product's performance characteristics. Historically there has been a shift from batch treatments to continuous injection of chemical at the wellhead. Since continuous injection is more efficient in terms of protection achieved per gallon of chemical, lower volumes of chemical would be required to achieve the same or better level of inhibition. The ultimate measure of whether or not effective levels of corrosion inhibitor are being used can only be determined by consideration of factors such as corrosion monitoring data and/or the amount of active corrosion detected by the inspection program.

Another measure of chemical optimization is the amount of corrosion inhibitor used relative to the volume of water produced from the reservoir. GPB Table A.8 summarizes the annual water production, corrosion inhibitor volumes, and corrosion inhibitor concentrations since 1995. The inhibitor volumes are expressed as a 'winter product equivalent', i.e. the lower volumes of highly concentrated chemical used during the summer have been normalized to the winter equivalent.

Year	H_2O Production 10^6 bbl/yr	Water Cut %	CI Usage 10^6 gal/yr	CI Concentration ppm
1995	455	59	1.62	85
1996	460	62	2.05	106
1997	457	62	2.21	115
1998	426	66	2.53	141
1999	416	68	2.28	130
2000	438	70	2.73	148
2001	398	70	2.63	157
2002	407	71	2.45	143
2003	408	72	2.52	147
2004	422	74	2.67	151
2005	431	76	2.66	147
2006	306	74	1.99	155
2007	349	76	2.34	160
2008	373	77	2.54	162
2009	348	77	2.42	166

GPB Table A.8 Summary of the Chemical Usage History

While the metrics in GPB Figure A.21 deal with chemical delivery at the overall field level, chemical optimization activity primarily focuses on injecting the correct amount of corrosion inhibitor to each piece of equipment. On a local level, the inhibitor requirement is driven by factors such as water cut, water volume, flow regime, velocity and condition of the equipment. Corrosion inhibitor rates for specific equipment vary over a wide range, from a few parts per million (ppm) to several hundred ppm. For 2009 the field-wide target chemical usage was 2.40 million gallons as compared to actual field-wide usage of 2.42 million gallons.



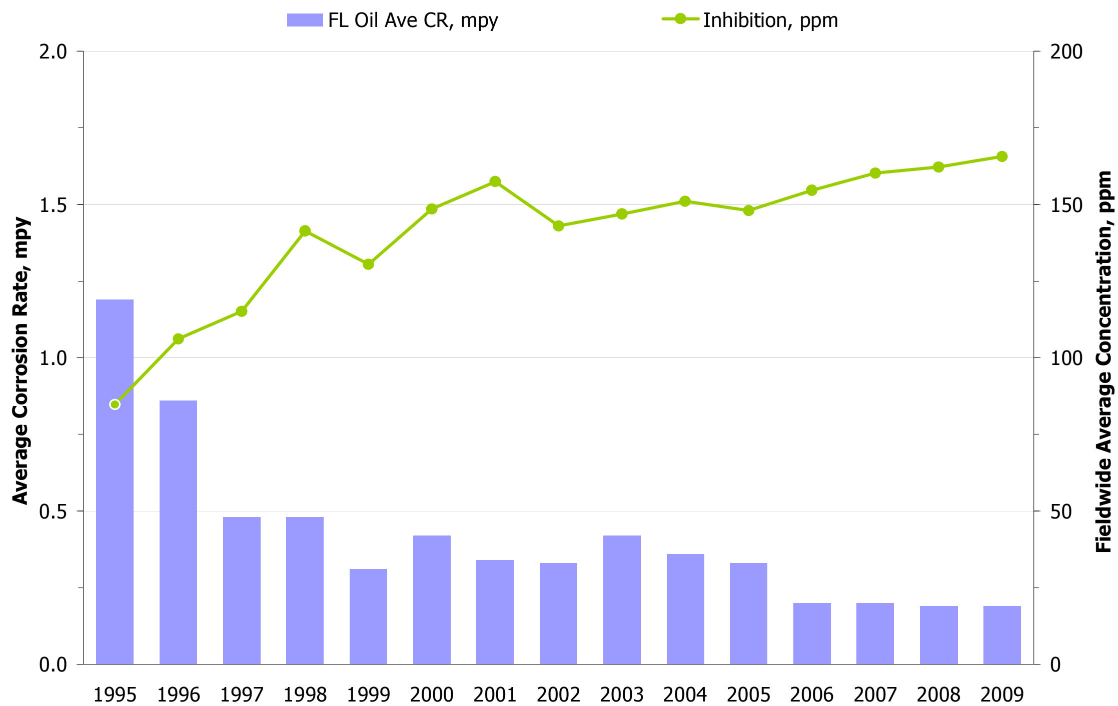
GPB Figure A.21 Field Wide Chemical Usage

Section A.2.4 3-Phase Corrosion Inhibition and Corrosion Rate Correlation

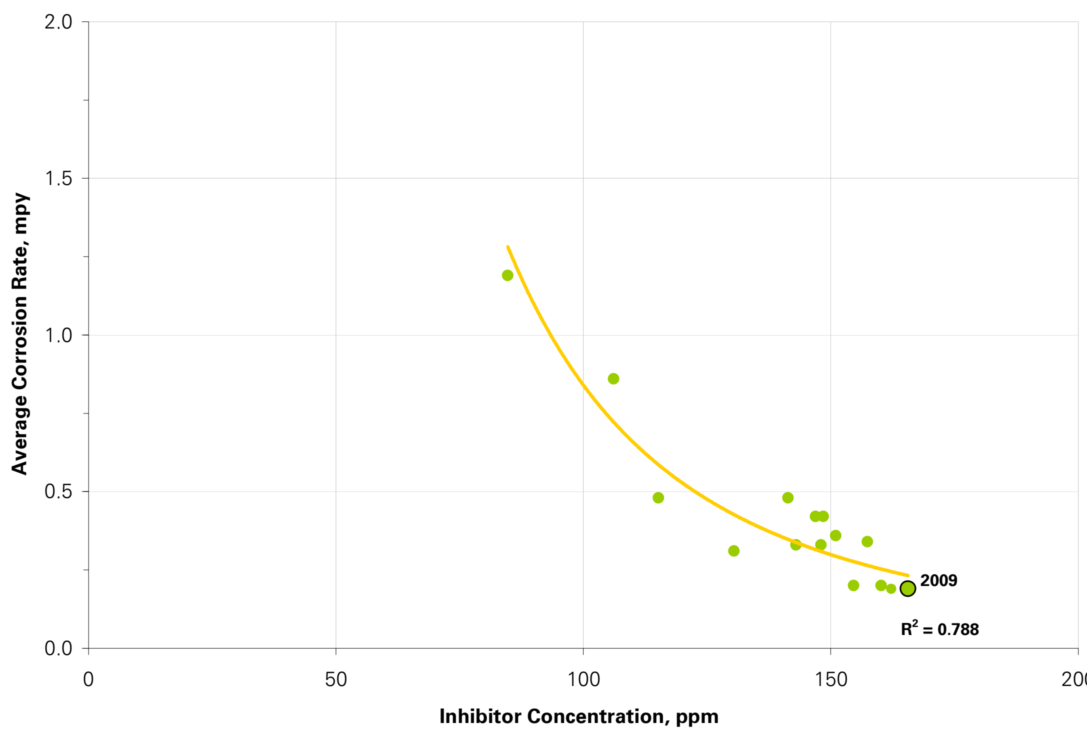
As discussed in Section A.1.1, the reductions in corrosion rates in the 3-phase production system flow lines and well lines are largely attributable to the implementation of an aggressive corrosion inhibition program across GPB.

GPB Figure A.22 shows the correlation between the increased level of corrosion inhibitor and the reduction in average WLC corrosion rate from 1995. As might be expected, the decline in average WLC corrosion rate correlates with the increase in corrosion inhibition levels over time. The figure also shows how additional corrosion inhibitor has reduced the average WLC corrosion rate through time.

GPB Figure A.23 shows the annual field-wide average corrosion inhibitor concentrations versus annual average WLC corrosion rates for 3-phase production flow lines. The figure shows how additional corrosion inhibitor has reduced the average WLC corrosion rate through time, but also shows the minimum corrosion rate (or maximum corrosion inhibitor efficiency) achievable through inhibition is approaching an asymptote of 0.25 mpy. Maintaining the current level of performance now becomes the goal for 3-phase flow line mitigation, while addressing any corrosion rate excursions on individual lines as they occur.



GPB Figure A.22 WLC Average Corrosion Rate versus Inhibitor Concentration



GPB Figure A.23 Corrosion Inhibitor Concentration vs. Average Corrosion Rate

Section A.2.5 Produced Water Inhibitor

Significant upgrades to the produced water chemical injection systems were completed in 2007. These upgrades allowed supplemental injection of corrosion inhibitor at all the processing facilities with the exception of LPC. The type and concentration of chemical that is used is intended to improve corrosion mitigation in the produced water system by helping to remove deposits and control MIC. Usage rates averaged 2,800 gallons per day for a total of 970,000 gallons for the year.

Section A.2.6 Produced Oil Inhibitor

Supplemental injection of corrosion inhibitor was initiated in 3Q06 at the five major facilities that produce processed crude into the GPB oil transit pipeline system. The rate of injection is based on total fluid production since significant water volumes are not typically present in produced oil. Usage rates averaged 132 gallons per day for a total of 48,000 gallons year.

Section A.2.7 Corrosion Inhibition Summary

In summary, corrosion inhibition covers a number of different areas from chemical testing and development, to field-wide deployment of new products delivering improved levels of corrosion control more cost effectively. This activity is ultimately directed toward one end; the reduction of corrosion rates. The effectiveness of the chemical optimization program in delivering improved control of corrosion rates is demonstrated by both monitoring and inspection results.

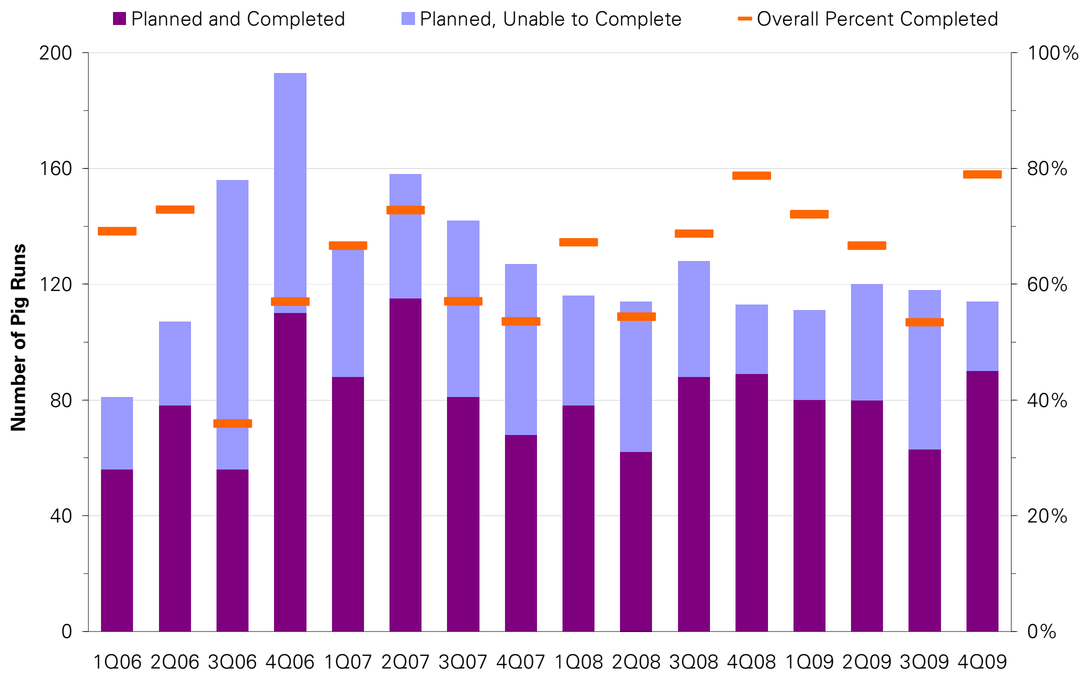
Section A.3 Maintenance Pigging

Maintenance (or cleaning) pigging is another tool that can be used for internal corrosion mitigation and management on certain pipelines. A maintenance pig is a device inserted at the upstream end of a pipeline that is then pushed downstream by pressure and flow in the system. The pig is then removed at the downstream end of the line. Maintenance pigs are manufactured in a wide range of designs and materials, based on their intended purpose, e.g. scraping, brushing, etc.

The operational characteristics of some lines may be such that continuous injection of corrosion inhibitor is not the sole approach to controlling corrosion. Maintenance pigging can be used to augment the corrosion management of these pipelines by improving contact between the chemical treatment and the pipe surface and promoting better chemical distribution over the length and circumference of the pipe. Maintenance pigs are also used to displace solids (e.g. biofilm, sand, scale) and water from the pipe and reduce the likelihood of under-deposit corrosion.

While maintenance pigging can be an important tool for managing internal corrosion, there are practical issues that routinely affect the execution of any maintenance pigging program. Limitations to wholesale application of pigging include the inability to launch or remove pigs, design restrictions in the pipe that prevent passage of the pig, and operating conditions where insufficient flow or pressure is available to move the pig.

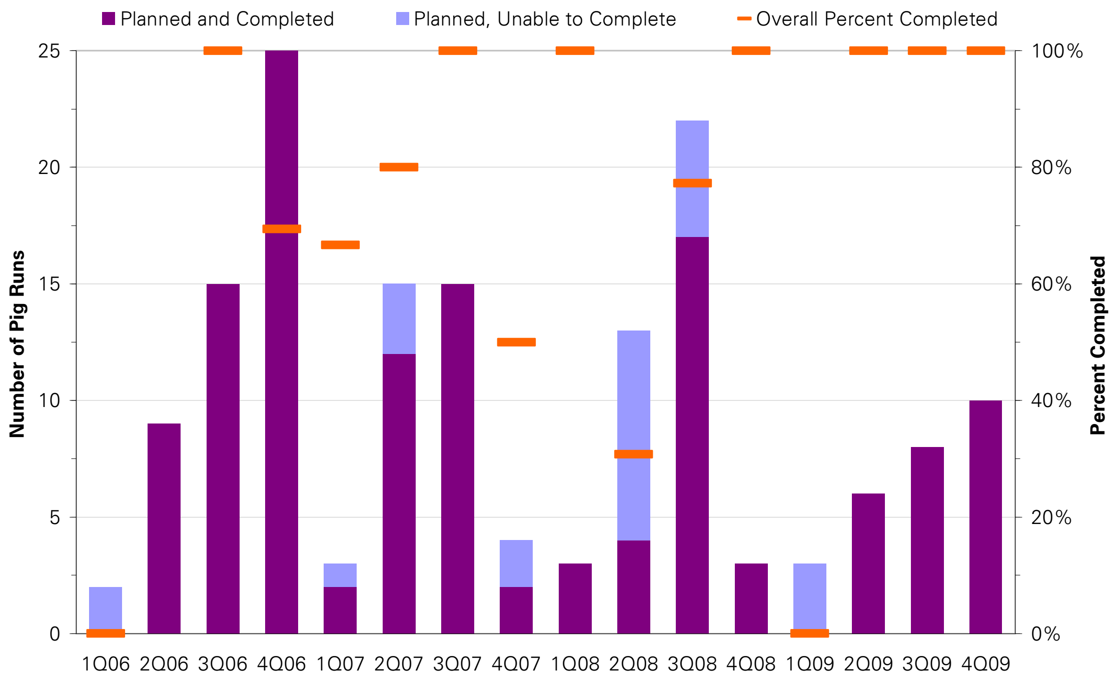
This is the third year in which maintenance pigging performance metrics have been included in this report. Data have been compiled from the 2006-2009 maintenance pigging programs at GPB, based on lines that are piggable. The metrics include the number of scheduled maintenance pig runs, the number of scheduled runs completed and the percent of scheduled runs completed, by year. GPB Figure A.24 shows the overall performance of the program since 2006 for scheduled pig runs on all service types. The average percentage of scheduled pig runs that were completed each year has increased for each of the last four years illustrating continuous improvement in the maintenance pigging program for GPB. For 4Q09, 79% of all scheduled maintenance pig runs were completed.



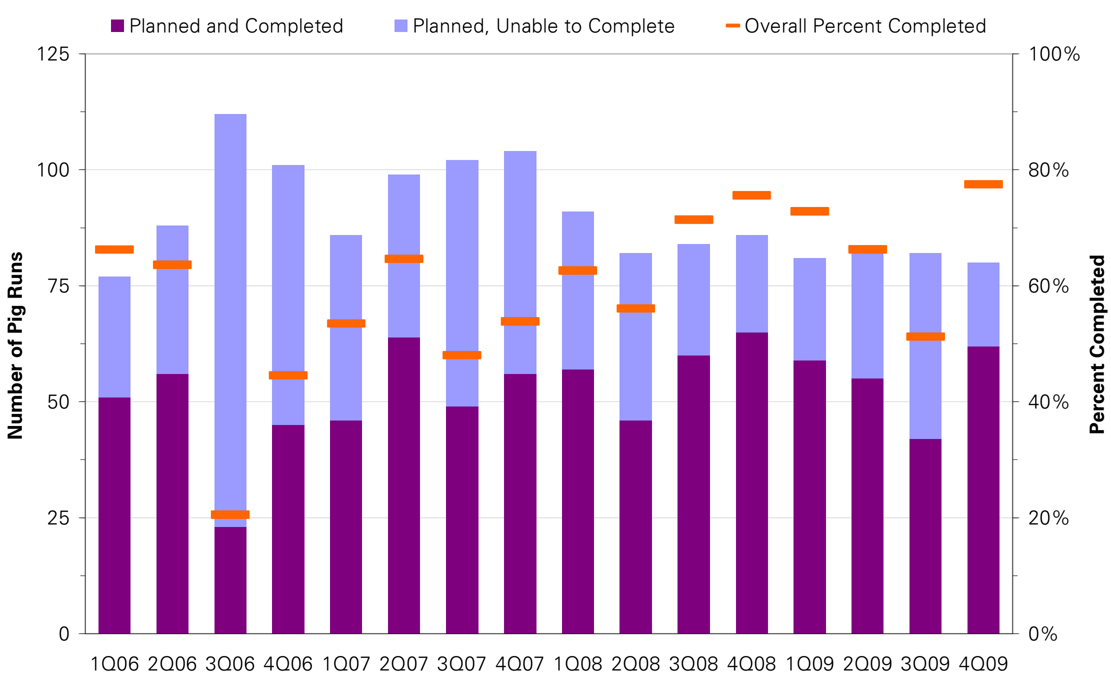
GPB Figure A.24 Maintenance Pig Runs Scheduled and Completed, All Service Types

Maintenance pigging schedules are established on an annual basis so that operations personnel can coordinate pigging activities with other operational and facility maintenance activities. Over the course of the year, weather conditions, equipment outages, and operating conditions may arise where it is not possible to complete or reschedule maintenance pig runs. The majority of uncompleted runs were due to either launchers or receivers being out of service for repair/replacement, or lines being shut in as a part of normal operational activities.

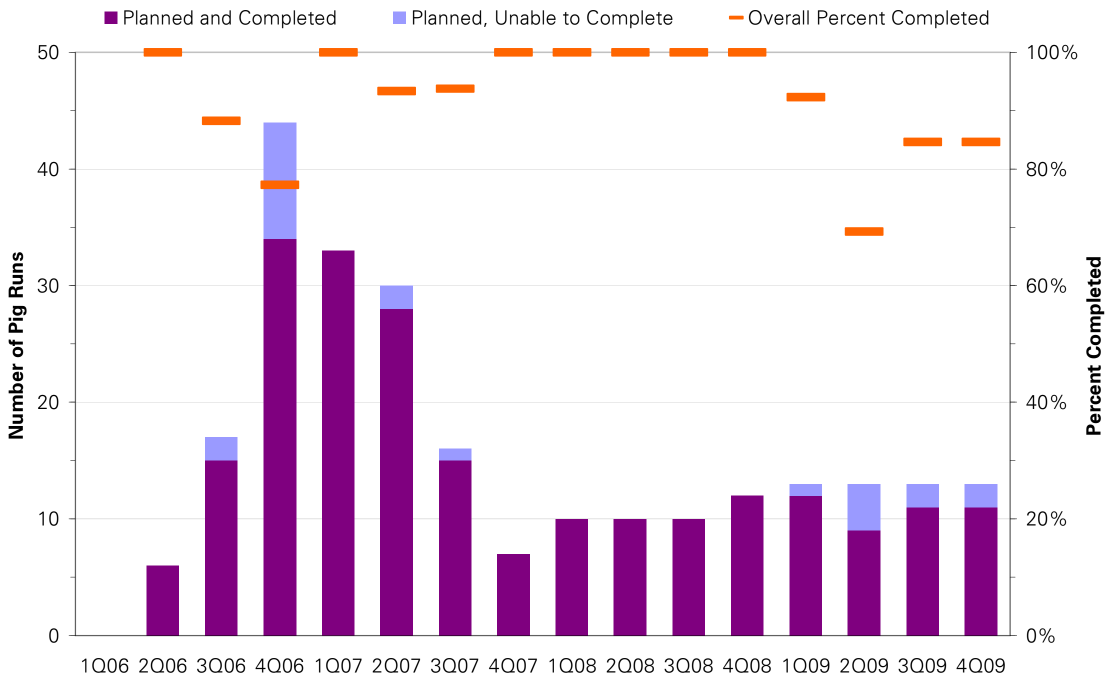
The following figures illustrate the maintenance pigging program metrics for the four major service types. GPB Figure A.25 presents the results of the maintenance pigging program for 3-phase oil lines where the annual percentage of completed runs significantly improved from 66% in 2008 to 89% in 2009. GPB Figure A.26 and GPB Figure A.27 present results for the produced water lines and processed oil lines. The maintenance pigging metrics for seawater service lines are shown in GPB Figure A.28. Although improvements were observed in the number of pig runs completed for produced water and seawater lines, equipment outages continue to challenge maintenance pig frequency objectives.



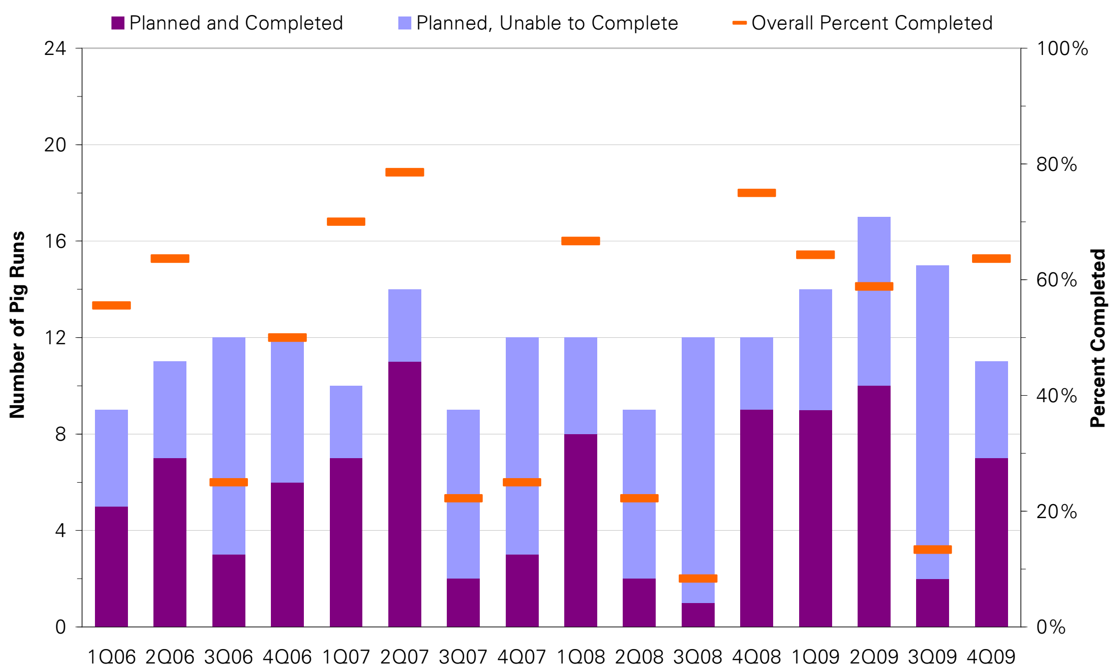
GPB Figure A.25 Maintenance Pig Runs Scheduled and Completed, 3 Phase Oil Service



GPB Figure A.26 Maintenance Pig Runs Scheduled and Completed, Produced Water Service



GPB Figure A.27 Maintenance Pig Runs Scheduled and Completed, Processed Oil Service



GPB Figure A.28 Maintenance Pig Runs Scheduled and Completed, Seawater Service

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GPB Section B

External/Internal Inspection

Section B GPB External/Internal Inspection

The inspection program encompasses piping, piping components, pressure vessels and tanks across GPB. Nondestructive techniques such as radiographic imaging and ultrasonic evaluation are used for the majority of the inspections. There are also specialized techniques for specific applications. The details for these techniques are shown in Appendix 3.3.3 and Appendix 3.3.4.

A number of factors contribute to the selection and allocation of inspection resources including, but not limited to, current equipment condition, current known corrosion rate (from inspection or corrosion monitoring), operational risks associated with transported fluids, type of corrosion mitigation, operation, design and age of the equipment.

Section B.1 External Inspection

This section summarizes the inspections performed to detect external corrosion and the results of those inspections. GPB Table B.1 summarizes the CUI inspection program for the period 1995 to 2009 separated by service and equipment type and the aggregate data. These aggregate data include both baseline and repeat inspections.

These data suggest the occurrence of external corrosion is related to the service type. This dependence is driven in part by the difference in operating temperature between services. There is also variability in damage occurrence on insulated pipe susceptible to CUI based on the location and orientation of the pipe. For additional information about CUI, refer to Appendix 3.3.4.

The CUI program covers all cross-country flow lines and well lines. There are approximately 300,000 weld packs at GPB, of which approximately 200,000 are off-pad and 100,000 are on-pad.

In order to manage CUI, a recurring inspection program has been implemented as the best method to identify equipment and locations susceptible to CUI. Prioritization of inspection surveys is determined by configuration, average temperature of the equipment, age of equipment, health, safety, environment (HSE), and/or the last time a complete inspection was completed. As a result of findings from inspections, the extent or recurring frequency of any additional examinations is determined.

	Flow Line			Well Line and piping			Aggregate		
Service	**# Insp.**	**# Corr**	**% Corr**	**# Insp.**	**# Corr**	**% Corr**	**# Insp.**	**# Corr**	**% Corr**
3-Phase Oil	70,911	2,537	4%	106,257	2,690	3%	177,168	5,227	3%
Processed Oil	5,105	168	3%	318	6	2%	5,423	174	3%
Gas	90,272	2,814	3%	62,050	601	1%	152,322	3,415	2%
Other	2,358	26	1%	4,367	105	2%	6,725	131	2%
Water	33,421	1,093	3%	18,910	392	2%	52,331	1,485	3%
Total	**202,067**	**6,638**	**3%**	**191,902**	**3,794**	**2%**	**393,969**	**10,432**	**3%**

GPB Table B.1 CUI Inspections by Service Type, 1995-2009

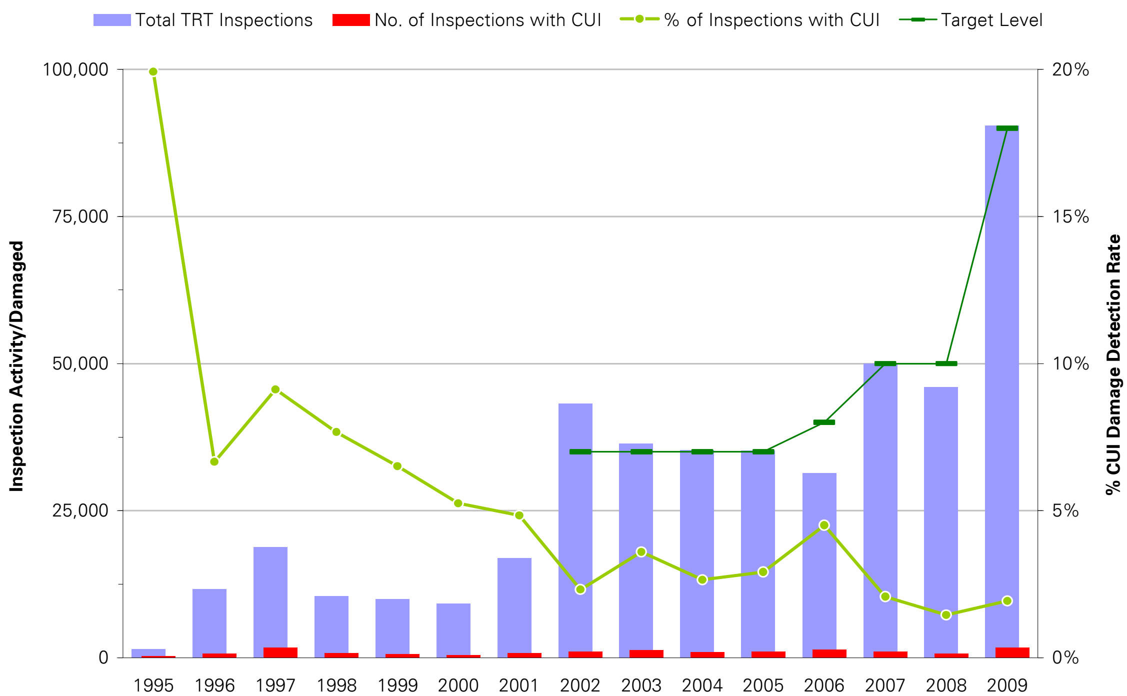
Section B.1.1 External Inspection Program Results

GPB Table B.2 and GPB Figure B.1 show the number and results of the external corrosion inspections performed since 1995. The data includes all the Tangential

Radiographic (TRT) techniques applied to detect external corrosion, including Automated-TRT (ATRT), and C-Arm Fluoroscopy (CTRT).

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Well Line & piping															
Activity Level	-	276	1,918	959	2,465	5,214	13,068	24,321	12,186	14,143	21,581	17,237	28,509	21,455	34,186
Corrosion Detected	-	20	245	67	101	229	712	348	142	308	330	517	320	209	679
% Corroded	-	7%	13%	7%	4%	4%	5%	1%	1%	2%	2%	3%	1%	1%	2%
Transit & Flow Line															
Activity Level	1,471	11,420	16,898	9,517	7,550	3,997	3,814	18,870	24,168	21,147	13,653	14,125	21,516	24,557	56,218
Corrosion Detected	241	759	1,471	737	551	254	105	652	1,167	627	697	895	718	460	1,063
% Corroded	16%	7%	9%	8%	7%	6%	3%	3%	5%	3%	5%	6%	3%	2%	2%
GPB Overall															
Activity Level	1,471	11,696	18,816	10,476	10,015	9,211	16,882	43,191	36,354	35,290	35,234	31,362	50,025	46,012	90,404
Corrosion Detected	293	779	1,716	804	652	483	817	1,000	1,309	935	1,027	1,412	1,038	669	1,742
% Corroded	20%	7%	9%	8%	7%	5%	5%	2%	4%	3%	3%	5%	2%	1%	2%

GPB Table B.2 External Corrosion Activity and Detection Summary



GPB Figure B.1 External Corrosion Activity and Detection Summary

In general, the inspection levels over the period 1996 to 2001 remained relatively constant at an average of 13,000 per year. In 2002 the activity level was increased substantially, targeting 35,000 inspections per year. In 2007 and 2008 the number of planned inspections was increased to 50,000. Over 90,000 external inspections were completed in 2009; the highest number completed in the history of the program. Two percent of the external inspections had some level of corrosion detected.

Section B.1.2 Cased Piping Survey Results

A long-term management strategy consisting of repeat examinations, analysis of results and corrective action as warranted has been implemented for cased piping segments.

Currently, the preferred test methodologies to determine the presence of active corrosion are either LRGWUT and/or in-line inspection (ILI).

The 2009 program consisted of 528 examinations on 524 cased segments; several segments had multiple methods of examination. Baseline inspections were performed on 132 of the 524 segments, with the remaining 392 segments being repeat inspections. The primary methods of inspection for cased piping segments are long range guided wave ultrasonic testing, excavations and in-line inspection. GPB Table B.3 shows the total of LRGWUT, ILI and excavation inspection activity for cased pipe segments.

Service	LRGWUT	ILI	Excavation
Gas	131	21	8
3-Phase oil	202	37	4
Processed oil	2	36	-
PW/SW	33	53	1
Total	**368**	**147**	**13**

GPB Table B.3 Cased Pipe Survey Activity by Technique

There were 368 cased segments evaluated using LRGWUT; 278 of which were reported to have slight to moderate anomalies. Forty-three cased segments received less than 100% coverage by LRGWUT and will be reviewed for future inspection using other methods. Follow up activities may include monitoring of these segments with LRGWUT, evaluation for in-line inspection (ILI) and/or excavation.

One hundred forty-seven (147) cased segments were inspected with ILI. The 2009 inspections have shown little or no change in peak corrosion depth since the previous inspection.

As a result of the 2009 case piping survey, 33 segments will be evaluated for excavation and/or additional testing.

Section B.1.3 Excavation History

Excavations of cased pipeline segments are typically performed when inspection data indicates the likelihood of an active corrosion mechanism or significant degradation that cannot be mitigated by any other means (e.g. CUI).

GPB Table B.8 shows that for 2009, six locations were found with external corrosion damage, one location was found with internal corrosion damage and six locations had no corrosion damage.

The strategy and execution of the cased pipe assessment (survey and excavation) will continue to develop as the program is refined and more information and/or experience with emerging long-range inspection technologies are gained. Cased pipe assessment activity levels and improvements in inspection technology are recognized as areas for continuous improvement.

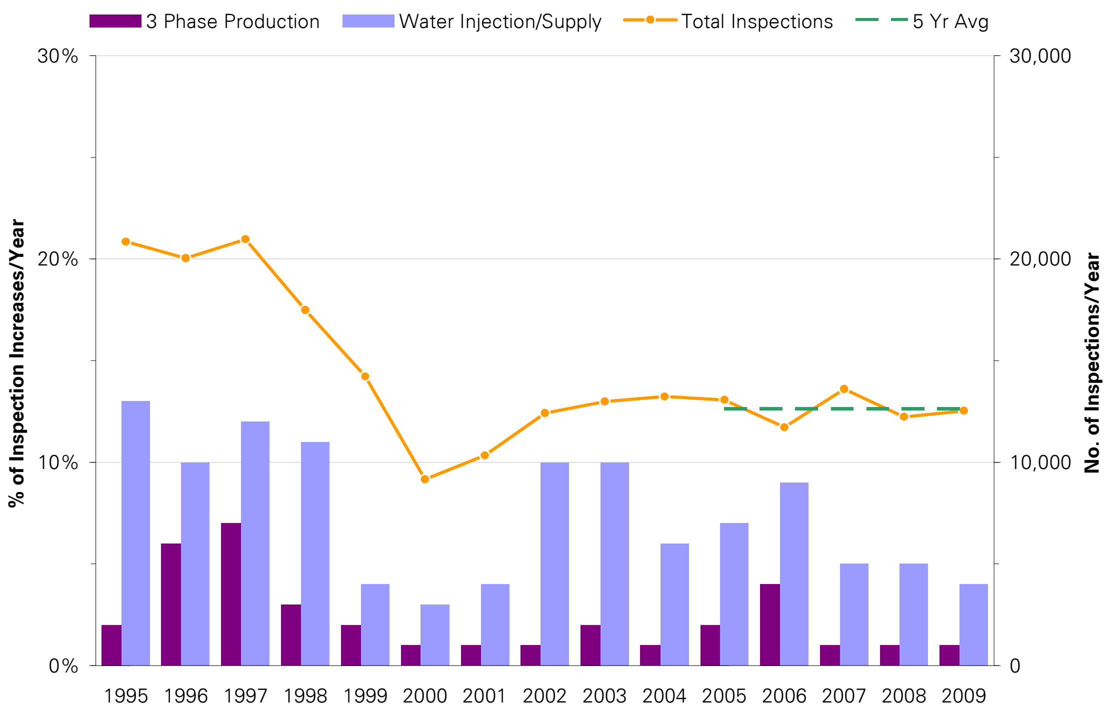
Section B.2 Internal Inspection Program Results

The results presented in this section are aggregate data obtained from flow line, oil transit line, and well line inspections. The program results are presented in terms of the number of locations that show an increase in corrosion damage since the last inspection as a percentage of the total number of repeat inspections.

$$\%\ \text{Inspection Increases} = \frac{\text{Locations with active corrosion}}{\text{Total \# of reinspected locations}} \times 100$$

The percentage of re-inspected locations showing increased corrosion (inspection increases) can be considered an indicator of active corrosion in a given system.

GPB Figure B.2 shows the percentage of inspection increases and the number of inspections per year for the flow lines segregated by 3-phase production and water injection (seawater and produced water) service. In 2009 the number of flow line inspections (12,538) was within 1% of the five year average.



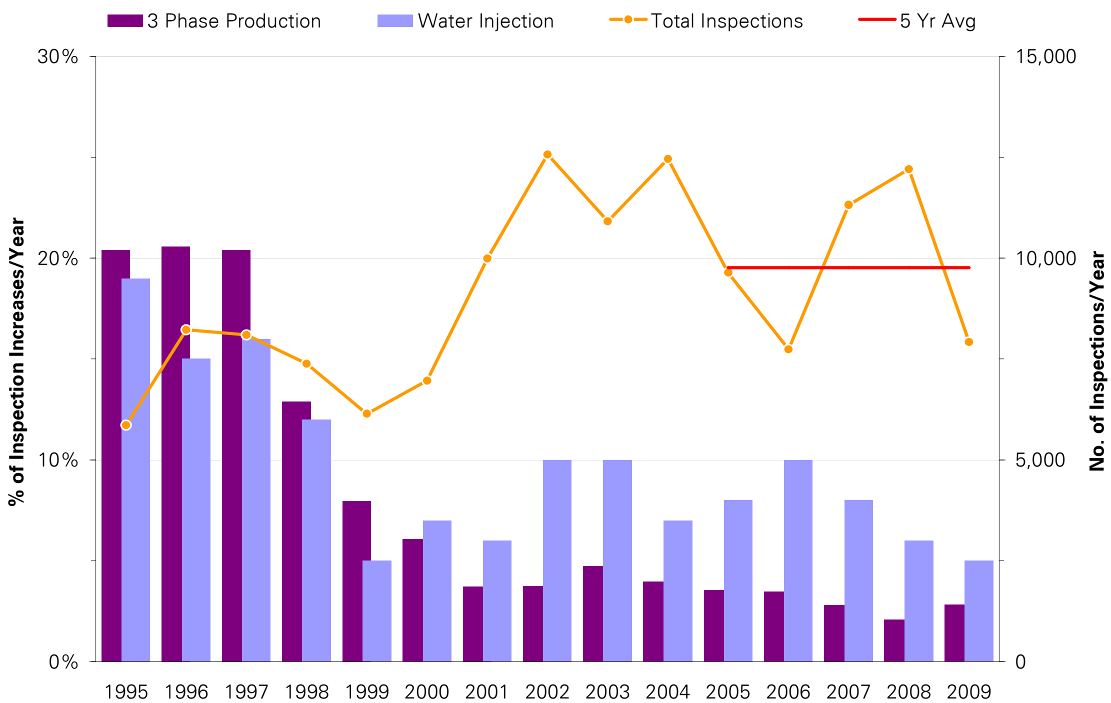
GPB Figure B.2 Flow Line Internal Inspection Increase by Service

The percentage of inspection increases in the 3-phase flow lines declined from a high of 7% in 1997 to 1% in 2000-2001. From 2007 through 2009 the number of internal inspection increases has remained at 1%. These values demonstrate the continued effectiveness of corrosion control in the flow lines.

For the water flow lines, the inspection data show continue to show improvement in corrosion control as compared to previous numbers of inspection increases. While the data is encouraging, the water injection system continues to be an area for improvement.

GPB Figure B.3 shows the percent inspection increases trend and the number of inspections per year for the well lines. The total number of inspections in 2009 was lower than the five year average as resources were focused towards a large increase in the external inspection program. The number of internal inspection increases in 2009 for 3-phase and water injection well lines continued the favorable trend of previous years.

For both the well lines and the flow lines, improvements in the chemical mitigation program are expected to continue adding to the level of corrosion control.



GPB Figure B.3 Well Line Internal Inspection Increase by Service

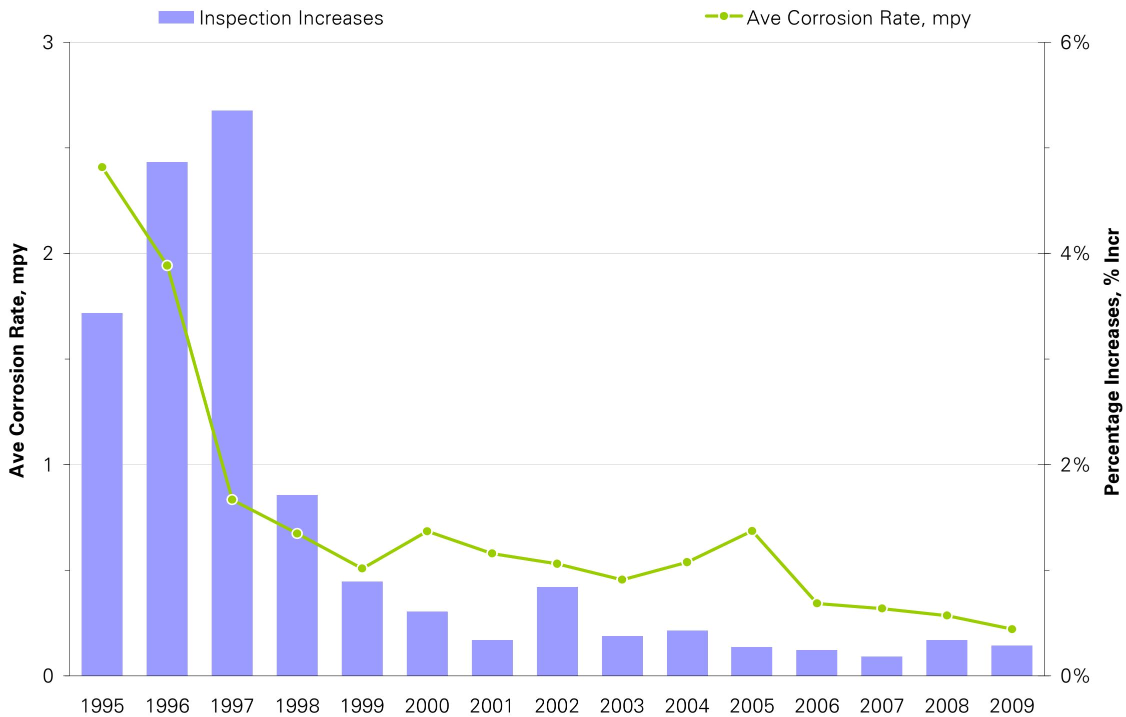
Section B.3 Correlation between Inspection and Corrosion Monitoring[9]

The following section describes the correlation between the inspection and monitoring programs for the 3-phase production system. Inspection and corrosion monitoring have different characteristics; in particular, inspection techniques are comparatively insensitive to short-term corrosion conditions, but are the most accurate as they measure actual wall loss of the pipe. In contrast, corrosion monitoring is more sensitive to short-term conditions but less accurate as a measure of corrosion rate since the weight loss coupon is not an integral part of the pipe wall. Therefore, in order to have confidence in the results from the corrosion monitoring program, it is also necessary to show that a correlation exists between the monitoring program and the results of the

[9] In addition to the Charter Work Plan, this information is supplied to provide additional context and help in understanding BPXA's corrosion management activities

inspection program. Refer to Appendix 3 - Table 12, for additional information regarding the inspection and monitoring techniques.

GPB Figure B.4 shows the trend for WLC average corrosion rate and the trend for percentage of inspections increases for the 3-phase well lines and flow lines. The trends for WLC and inspection results are consistent with each other and show a positive correlation. Also, the WLC trend precedes the inspection trend, as would be expected since coupons are a leading indicator. Similar trends have been observed for water service WLC and inspection data.



GPB Figure B.4 Correlation of WLC Corrosion Rate and % Inspection Increases, FL and WL 3-phase Production

The inspection results included in this analysis only include data which has an inspection interval (time since last inspection) of less than two years. The indicated reporting year has been changed to reflect the mid-point of the inspection interval, rather than the time of inspection as used in other figures in this report. This shift in time reporting compensates for the fact that corrosion can occur over the entire interval between inspections. Similarly, the weight loss coupon corrosion rates are reported as the mid-point of the exposure period, not the WLC removal date.

From the correlation between inspection and corrosion monitoring, a number of important conclusions can be drawn:

- Corrosion monitoring is considered a leading indicator and inspection is considered a lagging indicator. This is supported by the data, which shows a lag between corrosion monitoring and inspection changes.

- As the corrosion rates decrease due to the effectiveness of the inhibition program, further program optimization can be driven by the corrosion monitoring program, rather than by the inspection program.
- Because of the lower sensitivity of the techniques used in the inspection program, the corrosion rates in the 3-phase flow lines are below the detection limits for short term inspection intervals; therefore corrosion rate monitoring becomes a function of the coupon program, leaving inspection as a confirmation and integrity assessment tool.

In summary, the data in this section shows the correlation between the inspection data and the corrosion monitoring data. This in turn, allows the corrosion monitoring data to be used with confidence to manage the chemical treatment program in a responsive manner.

Section B.4 In-line Inspection

In-line inspection (ILI) tools, i.e. 'smart pigs', are an important tool for managing the long-term integrity of some pipeline systems. ILI is not however, the most appropriate or applicable inspection technology in all situations due to limitations imposed by operating parameters, environmental conditions, system design and accessibility of the pipelines.

Magnetic flux leakage (MFL) type ILI tools are frequently used at GPB where pigging facilities and process environment allow. Refer to Appendix 3.3.7 for additional information related to ILI at GPB.

In 2009, twenty-eight ILI runs were performed on GPB pipelines, collectively totaling nearly 90 miles of inspection. ILI was performed on nine 3-phase production flow lines. In addition, ILI was conducted on nine produced water flow lines and six processed oil lines. Sixteen of the lines had been previously assessed using ILI and twelve lines were inspected with ILI for the first time. GPB Table B.4 summarizes equipment service, diameter, and length of lines that were inspected using ILI in 2009.

The metal loss features reported by ILI are prioritized for verification by radiographic and/or ultrasonic inspection. Verification results are included in the aggregate inspection data. Additional follow-up of the reported features is an ongoing part of the normal radiographic and ultrasonic NDE activity at GPB.

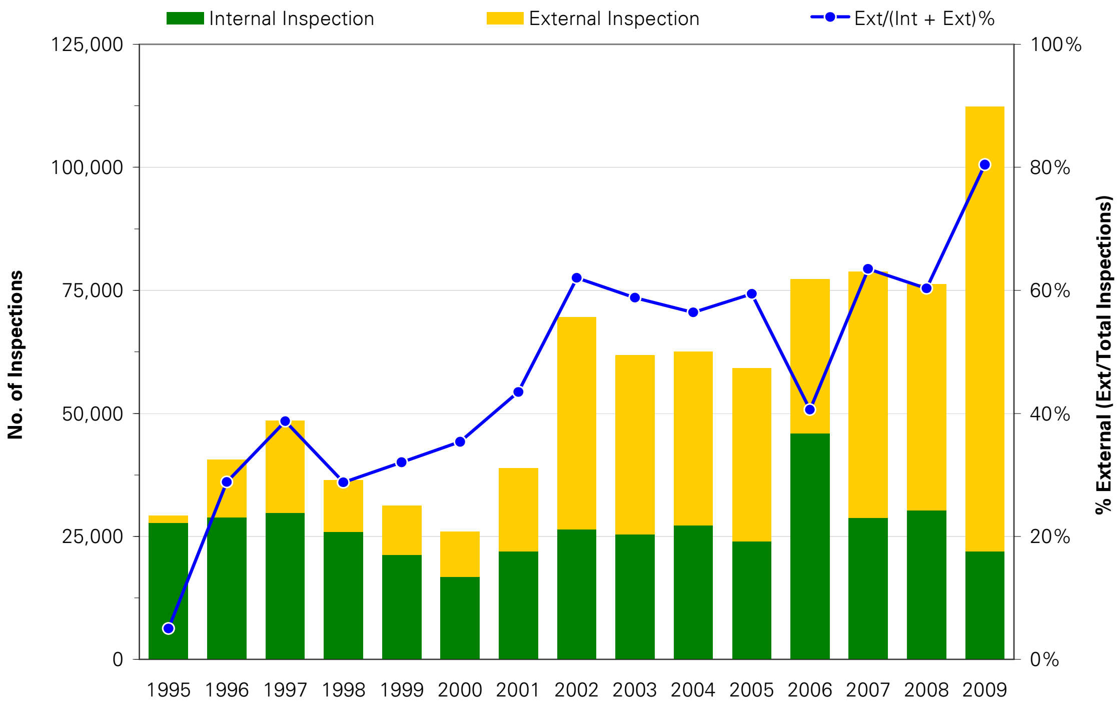
In summary, ILI will continue to be used to assist and complement the overall inspection program. These inspections form the basis of many of our programs and learnings.

Equipment	Service	Diameter (Inches)	Previous ILI	From	To	Length (miles)
04-SWI	PW	16	2002	FS-2 / IMF2	DS-04	1.3
11 SWI	SW	16	-	FS-2 / IMF2	DS-11	0.4
R-36	3-Phase	24	1994	Well Pad R	GC-2	3.3
OT21	PO	20	-	GC-2	GC-1	3.1
P-36	3-Phase	18	-	Well Pad P	Well Pad Y Jct.	2.8
09B	3-Phase	16	1994	DS-09	FS-2	3.1
LPC Oil Sales	PO	16	2006	LPC	PS-1	6.2
09A	3-Phase	24	1994	DS-09	FS-2	3.0
OT28	PO	28	-	GC-1	Skid 50	4.8
12B	3-Phase	16	1991	DS-12	FS-1	3.3
GLT-24-B	Gas	24	-	FS-3	GC-3	3.7
03D	3-Phase	16	1994	DS-03	FS-2	2.9
GLT-24-A	Gas	24	1996	GC-3	GC-2	6.2
09E	3-Phase	24	1994	DS-09	FS-2	3.1
GLT-24-C	Gas	24	-	FS-3	FS-2	7.0
X-74	3-Phase	24	2004	Well Pad X	GC-3	3.2
OT12	PO	12	-	FS-2	FS-1	3.0
XF-31	PO	24	-	GC-3	GC-1	2.3
15C	3-Phase	24	1992	DS-15	07C Tie-in Jct.	2.7
A-41	PW	6	1993	GC-3	Well Pad A	2.3
A-42	PW	6	1993	GC-3	Well Pad A	2.3
A-43	PW	6	1993	GC-3	Well Pad A	2.3
A-44	PW	6	1993	GC-3	Well Pad A	2.3
B-91	PW	6	-	GC-3	Well Pad B	1.4
B-97	PW	6	-	GC-3	Well Pad B	1.4
E-43	PW	6	-	GC-1	Well Pad E	3.4
S-69	PW	14	2001	Well Pad S	Well Pad M	3.1
OT18	PO	18	-	FS-1	Skid 50	4.9

GPB Table B.4 Completed Smart Pig (ILI) Assessments

Section B.5 Internal/External Inspection Comparison

GPB Figure B.5 and GPB Table B.5 summarize the level of internal and external inspection activity across GPB since 1995. Due to the events involving processed oil transit lines, the level of internal corrosion inspection during 2006 increased significantly when compared to other years. In 2009, external inspections comprised 79% of the total inspections performed for the year.



GPB Figure B.5 Internal and External Inspection Overall Activity for Transit, Flow and Well Lines

Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
External	1,471	11,696	18,816	10,476	10,015	9,211	16,882	43,191	36,354	35,290	35,234	31,362	50,025	46,012	90,404
Internal	27,713	28,884	29,745	25,939	21,241	16,836	21,939	26,425	25,488	27,254	24,040	45,922	28,757	30,263	21,988
Total	29,184	40,580	48,561	36,415	31,256	26,047	38,821	69,616	61,842	62,544	59,274	77,284	78,782	76,275	112,392
$\frac{Ext}{(Ext + Int)}$ %	5%	29%	39%	29%	32%	35%	43%	62%	59%	56%	59%	41%	63%	60%	80%

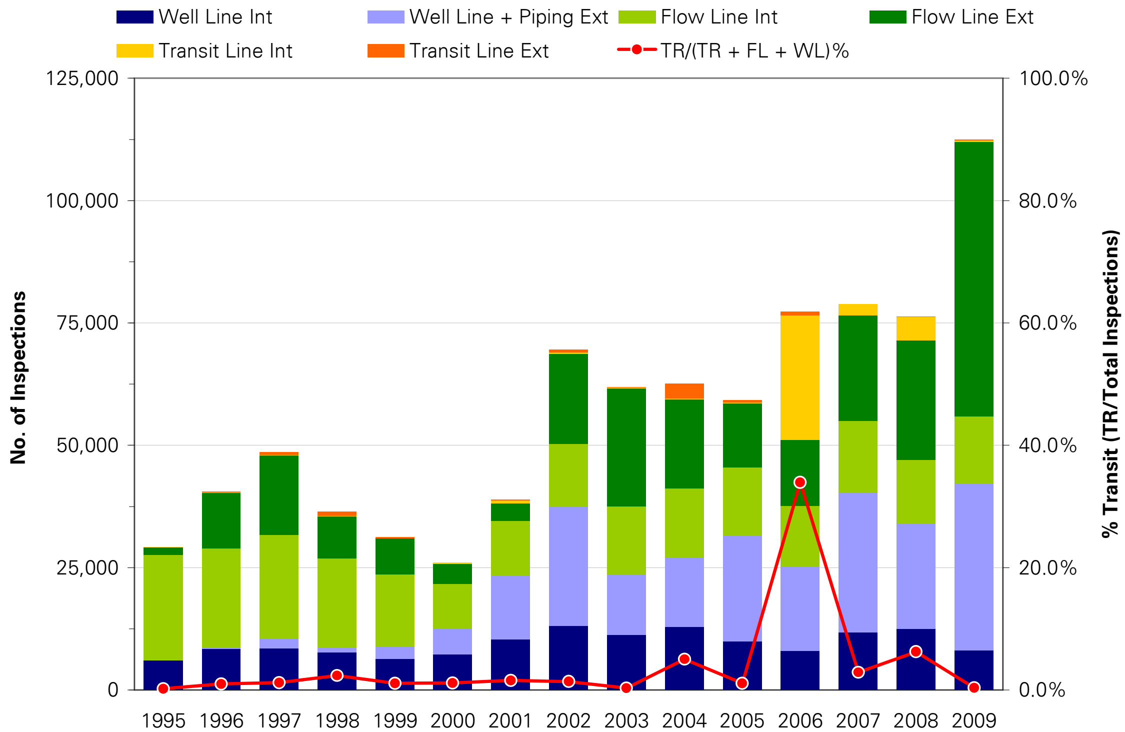
GPB Table B.5 Internal and External Inspection Activity

GPB Table B.6 and GPB Figure B.6 show the split between transit line, flow line and well line inspections for both the internal and external programs. A summary of the internal program results for specific service types is shown in GPB Table B.7 at the end of this section.

The overall inspection activity level was 112,392 inspections in 2009.

	Year	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Transit Line	External	-	173	540	834	281	-	118	566	4	2,996	497	751	-	44	129
	Internal	56	226	52	32	62	302	500	392	201	150	157	25,472	2,279	4,720	262
	Total	56	399	592	866	343	302	618	958	205	3,146	654	26,223	2,279	4,764	391
	Ext / (Ext + Int) %	-	43%	91%	96%	82%	-	19%	59%	2%	95%	76%	3%	-	1%	33%
Flow Line	External	1,471	11,247	16,358	8,683	7,269	3,997	3,696	18,304	24,164	18,151	13,156	13,374	21,516	24,513	56,089
	Internal	21,610	20,266	21,190	18,178	14,841	9,304	11,138	12,941	14,016	14,147	13,943	12,456	14,607	13,032	13,665
	Total	23,081	31,513	37,548	26,861	22,110	13,301	14,834	31,245	38,180	32,298	27,099	25,830	36,123	37,545	69,754
	Ext / (Ext + Int) %	6%	36%	44%	32%	33%	30%	25%	59%	63%	56%	49%	52%	60%	65%	80%
Well Line & Piping	External	-	276	1,918	959	2,465	5,214	13,068	24,321	12,186	14,143	21,581	17,237	28,509	21,455	34,186
	Internal	6,047	8,392	8,503	7,729	6,338	7,230	10,301	13,092	11,271	12,957	9,940	7,994	11,871	12,511	8,061
	Total	6,047	8,668	10,421	8,688	8,803	12,444	23,369	37,413	23,457	27,100	31,521	25,231	40,380	33,966	42,247
	Ext / (Ext + Int) %	-	3%	18%	11%	28%	42%	56%	65%	52%	52%	68%	68%	71%	63%	81%
	Grand Total	29,184	40,580	48,561	36,415	31,256	26,047	38,821	69,616	61,842	62,544	59,274	77,284	78,782	76,275	112,392
Transit Line	TR / (TR + FL + WL) %	0.2%	1.0%	1.2%	2.4%	1.1%	1.2%	1.6%	1.4%	0.3%	5.0%	1.1%	33.9%	2.9%	6.2%	0.3%
Flow Line	FL / (TR + FL + WL) %	79%	78%	77%	74%	71%	51%	38%	45%	62%	52%	46%	33%	46%	49%	62%
Well Line	WL / (TR + FL + WL) %	21%	21%	21%	24%	28%	48%	60%	54%	38%	43%	53%	33%	51%	45%	38%

GPB Table B.6 Internal and External Inspection Activity Summary by Transit (TR), Flow (FL) and Well Line (WL)



GPB Figure B.6 Internal and External Inspection Activity Summary by Flow/Well Line

Section B.6 Inspection Summary

In summary, the main observations from the inspection section are as follows;

External Program

- More than 100% percent of the planned external inspections were completed.
- Only 2% of the external inspection locations on transit and flow lines had CUI damage present, continuing the declining trend observed from previous years. The percentage of external corrosion detection was only 1% for well lines.

Cased Piping

- The long-term management strategy was continued for cased piping segments consisting of repeat inspections and excavation. The target was 200 cased segments; 524 segments were inspected using a combination of techniques and thirteen casing excavation inspections were completed.

Internal Program

- The internal inspection results show continued improvement of corrosion control in the water service well lines.
- The percentage of inspections showing increases remained consistently low for the 3-phase flow lines (1%) and showed continued improvement for water service flow lines (4%).

- The total number of internal inspections was lower than the five year average due to the increased focus of resources on the CUI program.
- The results of the inspection program and the weight loss coupon program for the 3-phase oil service continue to be strongly correlated.

ILI Program

- In 2009, twenty-eight ILI runs were performed on GPB pipelines - nearly twice the number of ILI runs performed in 2008 and well exceeding the 20 ILI runs targeted for 2009.

BU	Type	Service	Result	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
GPB	FL	OIL	I	367	917	1,155	394	239	68	62	103	147	101	180	251	63	79	60
			NC	15,206	15,793	16,558	14,956	12,070	8,209	7,103	8,703	9,113	10,640	9,068	6,156	9,217	8,188	8,992
			NL	3,603	2,115	1,963	455	368	145	1,786	2,034	1,943	811	1,697	3,347	1,927	1,849	1,339
			%I	2%	5%	7%	3%	2%	1%	1%	1%	2%	1%	2%	4%	1%	1%	1%
			Total	19,176	18,825	19,676	15,805	12,677	8,422	8,951	10,840	11,203	11,552	10,945	9,754	11,207	10,116	10,391
		WTR	I	170	126	153	197	73	20	43	138	176	107	141	147	112	96	71
			NC	1,154	1,081	1,128	1,566	1,569	727	1,109	1,180	1,546	1,584	1,792	1,564	2,177	1,775	1,533
			NL	423	115	134	92	75	61	353	402	218	218	278	369	231	289	577
			%I	13%	10%	12%	11%	4%	3%	4%	10%	10%	6%	7%	9%	5%	5%	4%
			Total	1,747	1,322	1,415	1,855	1,717	808	1,505	1,720	1,940	1,909	2,211	2,080	2,520	2,160	2,181
		FL Total		20,923	20,147	21,091	17,660	14,394	9,230	10,456	12,560	13,143	13,461	13,156	11,834	13,727	12,276	12,572
GPB	TR	PO/NGL	I	12	12	4		10	161	81	7	3	12	10	114	23	9	3
			NC	34	81	46	20	26	59	191	338	92	110	90	1,325	1,177	1,052	218
			NL	10	133	2	12	26	82	228	47	106	28	57	24,033	1,079	3,659	41
			%I	26%	13%	8%	0%	28%	73%	30%	2%	3%	10%	10%	8%	2%	1%	1%
		PO Total		56	226	52	32	62	302	500	392	201	150	157	25,472	2,279	4,720	262
GPB	WL	OIL	I	630	903	876	602	312	266	213	278	324	290	232	157	197	150	157
			NC	2,461	3,490	3,424	4,084	3,634	4,135	5,537	7,171	6,579	7,118	6,339	4,393	6,868	7,084	5,412
			NL	958	1,741	1,953	699	575	510	2,439	3,377	2,244	2,380	1,234	1,425	1,901	2,565	771
			%I	20%	21%	20%	13%	8%	6%	4%	4%	5%	4%	4%	3%	3%	2%	3%
			Total	4,049	6,134	6,253	5,385	4,521	4,911	8,189	10,826	9,147	9,788	7,805	5,975	8,966	9,799	6,340
		WTR	I	225	260	201	211	71	124	79	125	145	152	107	130	129	104	54
			NC	1,018	1,531	1,073	1,620	1,414	1,745	1,282	1,135	1,339	2,132	1,227	1,125	1,533	1,671	963
			NL	614	356	621	216	174	249	491	533	359	519	533	518	723	653	578
			%I	18%	15%	16%	12%	5%	7%	6%	10%	10%	7%	8%	10%	8%	6%	5%
			Total	1,857	2,147	1,895	2,047	1,659	2,118	1,852	1,793	1,843	2,803	1,867	1,773	2,385	2,428	1,595
		WL Total		5,906	8,281	8,148	7,432	6,180	7,029	10,041	12,619	10,990	12,591	9,672	7,748	11,351	12,227	7,935
Total, All Inspections				26,885	28,654	29,291	25,124	20,636	16,561	20,997	25,571	24,334	26,202	22,985	45,054	27,357	29,223	20,769

Note:
I Increased Degradation from Previous Inspection
NC No Change from Previous Inspection
NL New Location 1st Inspection
%I Percent of Inspections with Increased Degradation = I/ (NC + I)

GPB Table B.7 Transit, Flow and Well Line Internal Inspection Data

Year	Cased Pipe Location	Equipment Excavated	Observation	Corrective Action
1992	COTU Access Road	FS1 to FS2 12" MI Distribution	10% external wall loss	Insulation/coating/tape repair
1995	S Pad West Entrance Crossing	S Pad 24" 3 Phase Production S Pad 14" Produced Water S Pad 10" Gas Lift S Pad 8" Miscible Injection	61% external wall loss 36% internal/ext wall loss 34% external Wall Loss 41% external wall loss	Sleeve/insulation/coat repair Sleeve/insulation/coat repair Insulation/coating repair Replaced segment/FBE
	GC1 Main Entrance	Distribution 24" Gas Lift Y Pad 24" 3 Phase Production	29% external wall loss 24% external wall loss	Insulation/coating repair Insulation/coating repair
	GC2 to GC1 Caribou Crossing	Distribution 24" Gas Lift Y Pad 24" 3 Phase Production	42% external wall loss 26% external wall loss	Sleeve/insulation/coat repair Insulation/coating repair
1996	GC-1 Spine Road	Distribution 24" Gas Lift D Pad 24" 3 Phase Production Y Pad 24" 3 Phase Production Distribution 20" Produced Wtr.	53% external wall loss 33% external wall loss 18% external wall loss 8% external wall loss	Sleeve/insulation/coat repair Insulation/coating repair Insulation/coating repair Insulation/coating repair
	E Pad Entrance	E Pad 24" 3 Phase Production	21% external wall loss	Insulation/coating repair
	GC3 to FS3 Caribou Crossing	Distribution 24" Gas Lift	No corrosion damage	None
	FS1 to FS2 Caribou Crossing	Distribution Natural Gas 30" Sales Oil 30" Distribution 24" Gas Lift Distribution 32" Sea Water	11% external wall loss 14% external wall loss No corrosion damage No corrosion damage	Insulation/coating/tape repair Insulation/coating/tape repair None None
1998	S Pad East Entrance Crossing	S Pad 10" Gas Lift	80% wall loss - ext rupture	Replaced segment
	GC2 to GC1 Caribou Crossing	Distribution 24" Gas Lift	9% external wall loss	Insulation/coating repair
	GC2 to GC1 Q Pad Rd Crossing	Distribution 34" Natural Gas	No corrosion damage	Insulation/FBE coated

GPB Table B.8 Cased Piping Excavation History

Year	Cased Pipe Location	Equipment Excavated	Observation	Corrective Action
2000	S Pad East Entrance Crossing	S Pad 24" 3 Phase Production S Pad 14" Produced Water S Pad 8" Miscible Injection	60% external wall loss 50% external wall loss 25% external wall loss	Replaced segment/coat repair Replaced segment/coat repair Sleeve/insulation/coat repair
2003	GC2 to GC1 Caribou Crossing	Y Pad 24" 3 Phase Production	Leak -external corrosion	Partial excavation/sleeve repair
	X Pad Pipeline Access Rd Crossing	X Pad 24" 3 Phase Production	75% external wall loss	Partial excavation/sleeve repair
	F Pad Pipeline Access Rd Crossing	F Pad 24" 3 Phase Production	24% external wall loss	Partial excavation/none
	NGI Pad Road Crossing	NGI Pad 14" Gas Cap Injection	58% external wall loss	Replaced segment
2004	WGI to West Dock Road Crossing	AGI Pad 16" Gas Cap Injection	no corrosion damage	none
	CCP Pad Road Crossing	CCP/NGI-NGL 4" NGL	10% external wall loss	partial excavation/insulation tape repair
	GC1 Entrance Road Crossing	D Pad 24" 3 Phase Production	16% external wall loss	partial excavation/insulation tape repair
	GC1 to F Pad Caribou Crossing	F Pad 24" 3 Phase Production	21% external wall loss	partial excavation/insulation tape repair
	GC1 to GC2 Road Crossing	U Pad 6" Gas Lift Supply	5% external wall loss	partial excavation/insulation tape repair
	F Pad/Frontier Camp Rd Crossing	F Pad 24" 3 Phase Production	16% external wall loss	partial excavation/insulation tape repair
	F Pad Pipeline Access Rd Crossing	F Pad 24" 3 Phase Production	18% external wall loss	partial excavation/insulation tape repair
	GC1 to G Pad Caribou Crossing	G Pad 6" 3 Phase Production	no corrosion damage	none

GPB Table B.8 (Continued) Cased Piping Excavation History

Year	Cased Pipe Location	Equipment Excavated	Observation	Corrective Action
2004	Q Pad Access Road Crossing	GC3/GC2 12" MI Supply	9% external wall loss	partial excavation/insulation tape repair
		H Pad 24" 3 Phase Production	24% external wall loss	partial excavation/insulation tape repair
		Y Pad 12" PW Supply	39% external wall loss	partial excavation/insulation tape repair
	Q Pad Spur Road Crossing	Y Pad 12" PW Supply	12% external wall loss	partial excavation/insulation tape repair
	West Dock to GC1 Road Crossing	K Pad 24" 3 Phase Production	8% external wall loss	partial excavation/insulation tape repair
	GC2 to N Pad Caribou Crossing	N Pad 24" 3 Phase Production	37% external wall loss	partial excavation/insulation tape repair
	CCP Pad Road Crossing	NGI Pad 14" Gas Cap Injection	14% external wall loss	partial excavation/insulation tape repair
	S Pad Entrance Road Crossing	S Pad 24" 3 Phase Production	10% external wall loss	partial excavation/insulation tape repair
		S Pad 14" Produced Water	11% external wall loss	partial excavation/insulation tape repair
	U Pad Road Crossing	U Pad 6" Production Well Line	18% external wall loss	partial excavation/insulation tape repair
		U Pad 3" Gas Lift Well Line	16% external wall loss	partial excavation/insulation tape repair
	X Pad to B Pad Caribou Crossing	X Pad 24" 3 Phase Production	5% external wall loss	partial excavation/insulation tape repair
		X Pad 8" MI Supply	17% external wall loss	partial excavation/insulation tape repair
2005	X Pad Pipeline Access Road	X Pad 24" 3 Phase Production	24% external wall loss	insulation tape repair
	GC-1 Spine Road	Distribution 24" Gas Lift	30% external wall loss	sleeve/insulation/tape repair

GPB Table B.8 (Continued) Cased Piping Excavation History

Year	Cased Pipe Location	Equipment Excavated	Observation	Corrective Action
2005	GC-1 Spine Road	D Pad 24" 3 Phase Production	34% external wall loss	insulation tape repair
		Y Pad 24" 3 Phase Production	no corrosion damage	insulation tape repair
		Distribution 28" Produced Water	no corrosion damage	insulation tape repair
		GC1-GC2 24" 3 Phase Tie-line	no corrosion damage	insulation tape repair
2006	F-Pad to GC1 Caribou Crossing	F Pad 24” 3 Phase Production	43% external wall loss	insulation tape repair
	F-Pad to GC-1 Frontier Road Crossing	F Pad 24” 3 Phase Production	55% external wall loss	insulation tape repair
	X-Pad to GC-3 Caribou Crossing	X Pad 24” 3 Phase Production	19% external wall loss	insulation tape repair
		X Pad 6” Miscible Injection	24% external wall loss	insulation tape repair
	S-Pad West Road Crossing	S Pad 14" Produced Water	37% internal wall loss	insulation tape repair
	GC3 Pad Road Crossing	X Pad 24” 3 Phase Production	49% external wall loss	insulation tape repair
	B Pad Main Entrance Road Crossing	B Pad 6" Miscible Injection	no corrosion damage	none
	GC2 to GC-1 Caribou Crossing 1	Oil Transit 34” Processed Oil	leak - internal wall loss	demolished – removed piping
	GC2 to GC-1 Caribou Crossing 3	Oil Transit 34” Processed Oil	79% internal wall loss	demolished – removed piping
	GC2 to GC-1 Caribou Crossing 4	Oil Transit 34” Processed Oil	87% internal wall loss	demolished – removed piping
	C-Pad to GC-3 Access Road Crossing	Oil Transit 34” Processed Oil	31% internal wall loss	temporary insulation – planned replacement

GPB Table B.8 (Continued) Cased Piping Excavation History

Year	Cased Pipe Location	Equipment Excavated	Observation	Corrective Action
2006	GC3 to Sk-50 Caribou Crossing 1	Oil Transit 34” Processed Oil	17% internal wall loss	temporary insulation – planned replacement
	GC3 to Sk-50 Caribou Crossing 2	Oil Transit 34” Processed Oil	18% internal wall loss	temporary insulation – planned replacement
	GC3 to Sk-50 Caribou Crossing 3	Oil Transit 34” Processed Oil	13% external wall loss	temporary insulation – planned replacement
	GC3 to Sk-50 Caribou Crossing 4	Oil Transit 34” Processed Oil	no damage	temporary insulation – planned replacement
2007	GC3/GC2MI at casing CI136	Distribution 12" Miscible Injection	no damage	none
	GLT-24 at casing CI124	Distribution 24" Gas Lift	23% external wall loss	tape wrap & insulation repair
	GLT-24 at casing CI136	Distribution 24" Gas Lift	5% external metal loss	tape wrap & insulation repair
	GLT-24 at casing CI221	Distribution 24" Gas Lift	no damage	none
	S-804 at casing CI111	S Pad 8" Miscible Injection	8% external wall loss	tape wrap & insulation repair
	W-69 at casing CI180	W Pad 8" Produced Water	no damage	none
	W-74 at casing CI180	W Pad 24" 3 Phase Production	no inspection	planned replacement
	W-79 at casing CI180	W Pad 10" Gas Lift	no damage	none
2008	Fuel Gas at casing CI009	8” Fuel Gas to CPS	no damage	none
	Glycol at casing CI009	2” Glycol at CPS	no damage	none
	Instrument Air at casing CI009	1” Instrument Air at CPS	no damage	none
	K-74 at casing CI174	K Pad 24” 3 Phase Production	no damage	none

Year	Cased Pipe Location	Equipment Excavated	Observation	Corrective Action
2009	Casing R080 - NGI Supply-1	10" Gas Injection from CCP to North Gas Injection Wells 1, 2, 3 & 4	No Damage	None
	Casing R080 - NGI Supply-2	10" Gas Injection from CCP to North Gas Injection Wells 5, 6, 7	17% external metal loss	Tape wrap and reinsulate
	Casing R080 - NGI Supply-3	10" Gas Injection from CCP to North Gas Injection Wells 8, 9, 10, 11, 12, 13, 14	19% external metal loss	Tape wrap and reinsulate
	Casing R080 - CCP/NGI NGL	4" NGL from Central Compression Pad to North Gas Injection Pad	18% external metal loss	Tape wrap and reinsulate
	Casing CI127 - E-46	10" Oil from E-Pad to GC1	No Damage	None
	Casing R137 - 04-38	6" Oil Well Line 04-38 on Drill Site 4	No Damage	None
	Casing CI076 - GLT24	24" Gas Lift from GC1 to GC2	No Damage	None
	Casing CI074 - GLT24	24" Gas Lift from GC1 to GC2	48% external metal loss	Tape wrap and reinsulate
	Casing CI151 - U-384	16" Oil from U-Pad to GC2	21% external metal loss	Tape wrap and reinsulate
	Casing R125 - 09AL	12" Gas Lift from Drill Site 09 to Drill Site 16/17 Tie	21% external metal loss	Tape wrap and reinsulate
	Casing R125 - 03SWI	16" Produced Water from Drill Site 03 to IMF2	No Damage	None
	Casing R125 - 09B	16" Oil from Drill Site 09 to FS2	10% internal metal loss	Tape wrap and reinsulate
	Casing C001 - ALGASTL	24" Artificial Lift from FS2 to FS3	No Damage	None

GPB Table B.8 (Continued) Cased Piping Excavation History

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GPB Section C

Corrosion & Structural Related Repairs and Spills

Section C GPB Corrosion & Structural Related Repairs and Spills

Section C.1 Repair Activities

The repair activities are summarized in GPB Table C.1. A total of 187 piping repairs were performed in 2009, including those on facility yard piping 'P' which are reported by exception for repairs or leaks.

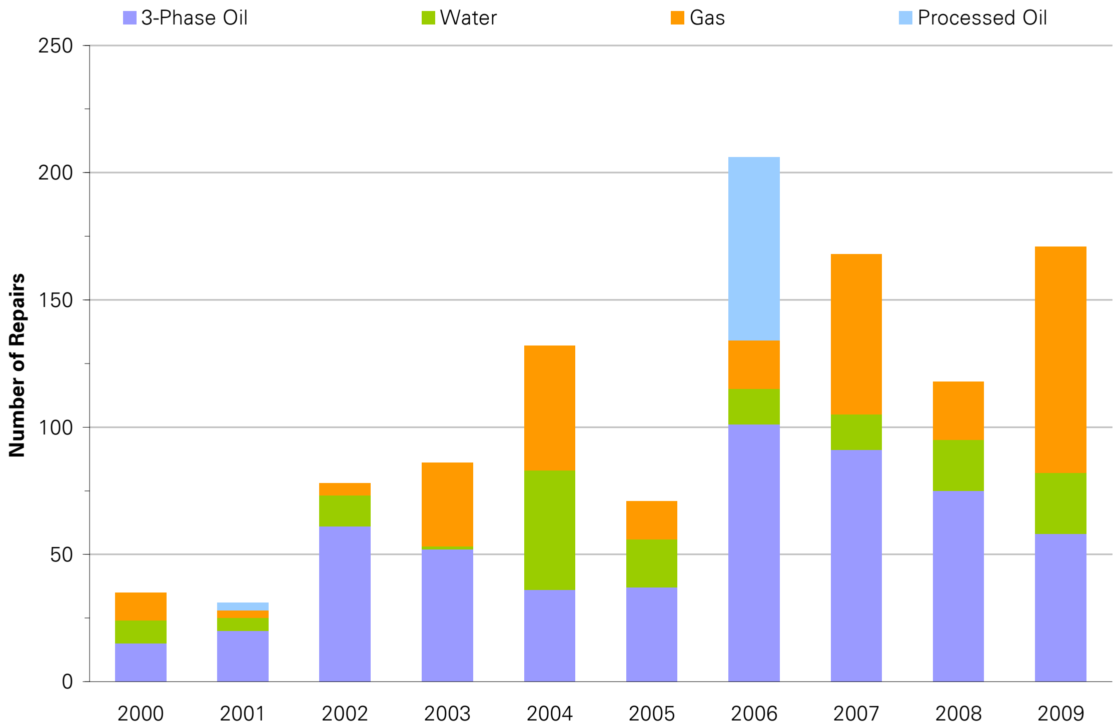
Service	Type	Internal	External	Mechanical	Total
3-Phase Oil	FL	1	13	23	37
	WL	1	9	11	21
	P	-	2	1	3
Water	FL	-	3	12	15
	WL	7	-	2	9
	P	-	1	1	2
Gas	FL	1	25	35	61
	WL	-	19	9	28
	P	3	-	1	4
PO	FL	-	-	-	0
	P	-	-	1	1
Other	P	1	-	5	6
Totals		14	72	101	187

GPB Table C.1 Repair Activity

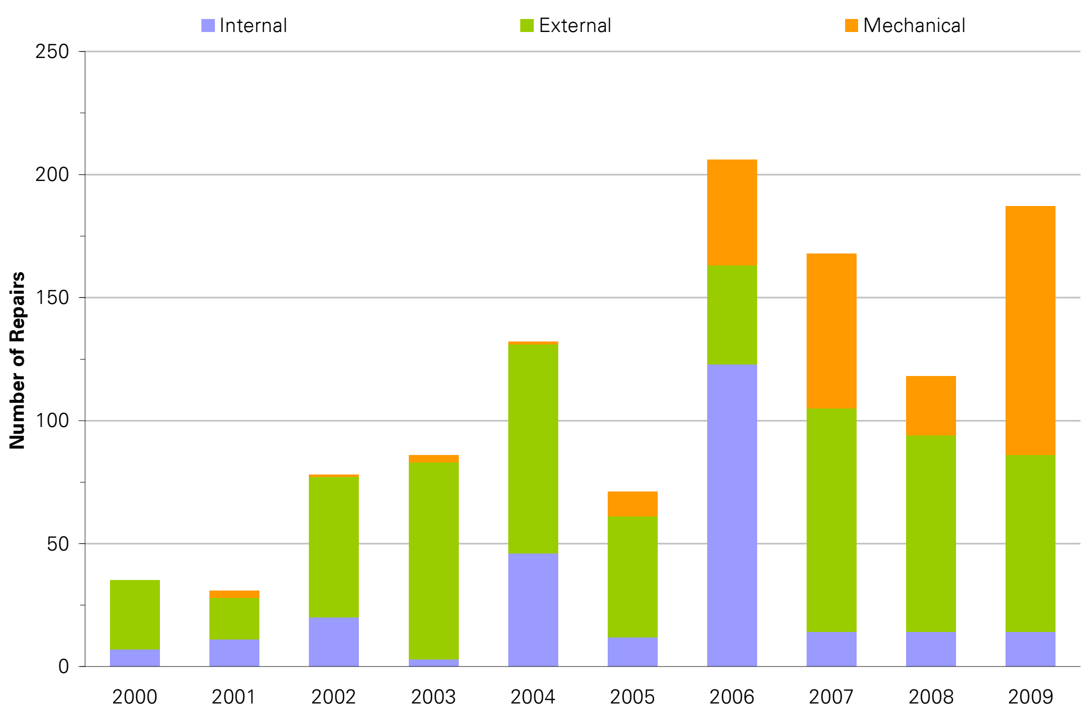
For flow lines, well lines and yard piping there were 72 repairs attributed to external corrosion and 101 repairs attributed to mechanical damage. Mechanical repairs are largely the result of manufacturing discontinuities in the pipe steel, or gouges and scratches that occurred during pipeline construction and were later found while inspecting for CUI.

There were 14 repairs attributed to internal corrosion, of which two were located on flow lines, eight were located on well lines, and four were located on yard piping.

GPB Figure C.1, GPB Figure C.2, GPB Figure C.3, and GPB Table C.2 show the 10-year trend in repairs grouped by service, damage mechanism, and equipment, respectively.



GPB Figure C.1 Repairs by Service



GPB Figure C.2 Repairs by Damage Mechanism

GPB Figure C.3 Repairs by Equipment

Year	Type	3 Phase Oil		Water		Gas		Processed Oil	Total
		Flow Line	Well Line	Flow Line	Well Line	Flow Line	Well Line	Transit Line	
2000	Internal	2	5	-	-	-	-	-	7
	External	1	7	2	7	8	3	-	28
	Mechanical	-	-	-	-	-	-	-	-
	Total	3	12	2	7	8	3	-	35
2001	Internal	2	4	1	1	-	-	3	11
	External	7	5	3	-	2	-	-	17
	Mechanical	-	2	-	-	-	1	-	3
	Total	9	11	4	1	2	1	3	31
2002	Internal	8	7	1	4	-	-	-	20
	External	35	11	6	1	4	-	-	57
	Mechanical	-	-	-	-	1	-	-	1
	Total	43	18	7	5	5	-	-	78
2003	Internal	-	3	-	-	-	-	-	3
	External	28	20	-	1	23	8	-	80
	Mechanical	1	-	-	-	1	1	-	3
	Total	29	23	-	1	24	9	-	86
2004	Internal	5	5	23	13			-	46
	External	13	13	9	1	12	37	-	85
	Mechanical	2	-	1	-			-	3
	Total	20	18	33	14	12	37	-	134
2005	Internal	1	1	5	5	-	-	-	12
	External	27	7	-	7	4	4	-	49
	Mechanical	1	-	1	1	4	3	-	10
	Total	29	8	6	13	8	7	-	71
2006	Internal	64	2	2	10	-	-	45	123
	External	20	5	-	1	2	11	1	40
	Mechanical	8	2	1	-	1	5	26	43
	Total	92	9	3	11	3	16	72	206
2007	Internal	3	4	-	7	-	-	-	14
	External	50	13	-	2	19	7	-	91
	Mechanical	20	1	4	1	32	5	-	63
	Total	73	18	4	10	51	12	-	168
2008	Internal	3	4	-	7	-	-	-	14
	External	43	11	9	-	11	6	-	80
	Mechanical	11	3	4	-	6	-	-	24
	Total	57	18	13	7	17	6	-	118
2009	Internal	1	1	-	7	1	-	-	10
	External	13	9	3	-	25	19	-	69
	Mechanical	23	11	12	2	35	9	-	92
	Total	37	21	15	9	61	28	-	171
Grand Total		**392**	**156**	**87**	**78**	**191**	**119**	**75**	**1,098**

GPB Table C.2 Historical Repairs by Service

Section C.2 Corrosion and Structural Related Leaks

This section summarizes the corrosion and structural related incidents that occurred in 2009 and provides a historical perspective on leaks (loss of containment) and saves (repairs before leak of non-FFS equipment).

GPB Table C.3 summarizes the equipment, failure mechanism and volume of leaks that occurred in 2009. Of the 6 leaks that occurred, one was due to external corrosion, two were attributed to internal corrosion and three were mechanical.

Service	Location	Type	Date	Mechanism	Volume
3-Phase	09A	FL	Feb-09	External	1,932 gal
Diesel	MOWF	P	May-09	Mechanical/Fatigue	117 gal
Nitrogen	TL-21	FL	Jul-09	Internal	1,500 mscf
Produced Water	DS04	WL	Aug-09	Internal	<1 gal
3-Phase	16D	FL	Nov-09	Mechanical/Fatigue	10 gal
3-Phase	LS03	FL	Nov-09	Mechanical/Ice	46,000 gal

	Surface		Service					Mechanism			
	Int	Ext	OIL	SW	PW	Gas	Othr	CO_2	Int	CUI	Mech
WL	1	-	-		1	-	-	-	1	-	-
FL	2	2	3	-	-	1	-	-	1	1	2
TR	-	-	-	-	-	-	-	-	-	-	-
P	-	1	-	-	-	-	1	-	-	-	1

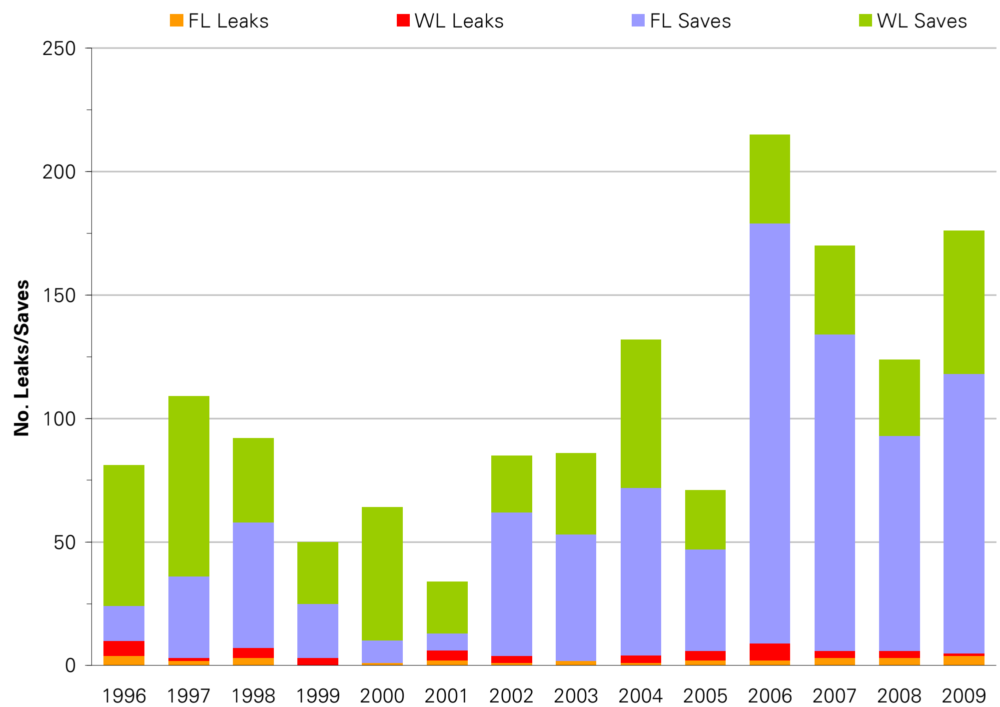
GPB Table C.3 Leaks Due to Corrosion/Mechanical

GPB Table C.4, GPB Figure C.4 and GPB Figure C.5 show the number of corrosion/mechanical related leaks and saves since 1996. The ratio of leaks to saves provides a high level measure of the performance of the inspection program at detecting severe damage before it results in a failure. A 'save' is defined as a location found via the inspection program that warrants a repair, system de-rate, replacement or removal from service as the equipment no longer meets the FFS criteria defined in Appendix 3.3.6. It should be noted that items are typically scheduled for repair at 105%

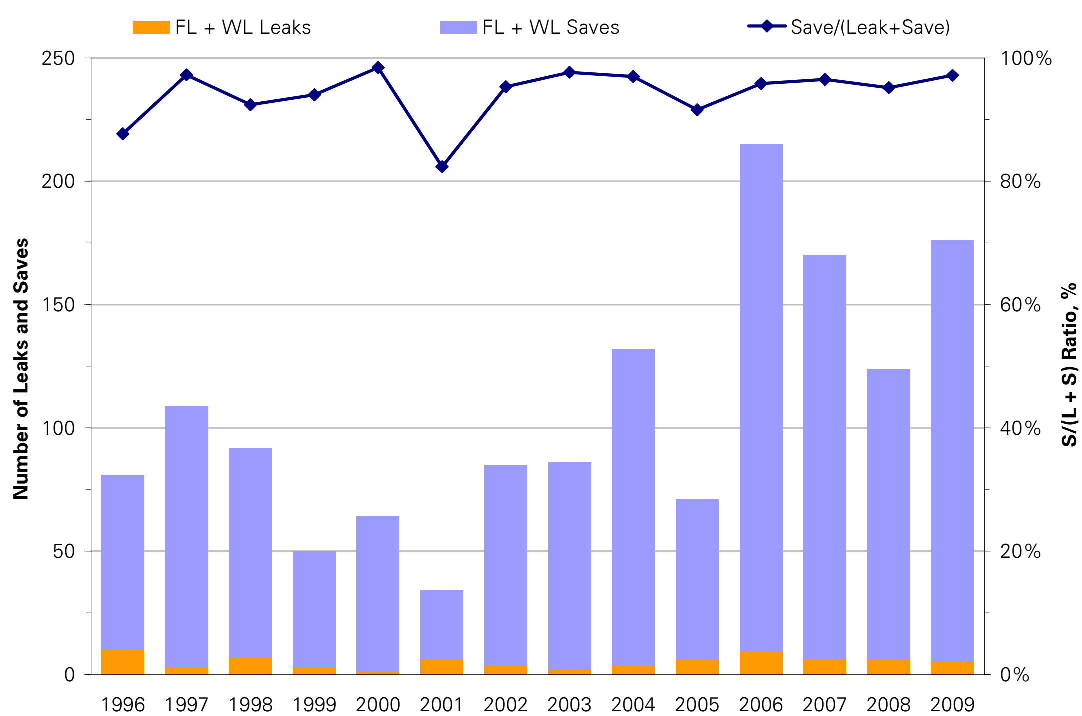
of MAOP, to allow time to schedule and complete the repair before the item requires removal from service.

	Transit & Flow Lines			Well Lines			Total
	Saves	Leaks	$\frac{S}{(L+S)}\%$	Saves	Leaks	$\frac{S}{(L+S)}\%$	$\frac{S}{(L+S)}\%$
1996	14	4	78%	57	6	90%	88%
1997	33	2	94%	73	1	99%	97%
1998	51	3	94%	34	4	89%	92%
1999	22	0	100%	25	3	89%	94%
2000	9	1	90%	54	0	98%	97%
2001	7	2	78%	21	4	84%	82%
2002	58	1	98%	23	3	89%	95%
2003	53	2	96%	33	0	100%	98%
2004	68	1	99%	60	3	95%	97%
2005	41	2	95%	24	4	86%	92%
2006	170	2	99%	36	7	84%	96%
2007	128	3	98%	36	3	92%	96%
2008	87	3	97%	31	3	91%	95%
2009	113	4	97%	58	1	98%	97%

GPB Table C.4 Historical Corrosion/Mechanical Leaks and Saves



GPB Figure C.4 Historical Corrosion/Mechanical Leaks and Saves by Line Type



GPB Figure C.5 Historical Corrosion/Mechanical Leaks and Saves

Section C.3 Structural Integrity Issues

There are several activities designed to observe and report structural integrity issues. Structural integrity issues are related to damage caused by structural movement: i.e. subsidence, jacking, cyclic fatigue, impact, slugging, snow loading, etc.

Structural repairs to pipeline support members continued this year. The repairs were primarily pipeline re-leveling due to support member subsidence or jacking.

Section C.3.1 Walking Speed Survey

Where there is perambulatory access to facilities, a Walking Speed Survey (WSS) is performed. The WSS consists of a visual examination of process equipment and system components to identify mechanical integrity deficiencies. Anomalies are noted and evaluated by the Field Mechanical Piping Engineer for action as appropriate.

As the name implies, the observations are made at 'walking speed' and are focused on, but not limited to,

- Piping and insulation
- Structural components
- Electrical equipment
- Instrumentation equipment
- Communication equipment
- Chemical injection tubing
- Pipeline road and animal crossings

The WSS is a 5-year recurring program with the following schedule;

Last Completed	Next Scheduled	Equipment Description
2007	2012	GPB East Cross Country Pipelines
2008	2013	GPB West Cross Country Pipelines
2009	2014	GPB East Well Pads
2005	2010	GPB West Well Pads
2006	2011	Lisburne Cross Country Pipelines/Drill Sites

GPB Table C.5 Structural/Walking Speed Survey Schedule

A WSS of the GPB East Well Pads was completed in 2009.

Section C.3.2 Routine Surveillance

Field Operations and Security personnel are tasked as the primary identifiers of flow lines and well lines with potential structural integrity anomalies. Observations of wind-induced vibration, excessive pipe movement, out-of-place pipe guides, bent piping, etc. are reported.

An analysis of potential integrity anomaly is completed by a competent engineer to determine any required action. Additional analysis may be required by the Field Mechanical Piping Engineer or third party engineering experts.

For example, if excessive sagging between pipeline supports is observed, the engineer requests an NDE inspection of the affected area. The purpose of the NDE inspection is to determine if any detrimental condition (i.e. wall thinning, cracks, ovality, buckling, and strain) exists. The NDE methods typically used include visual, caliper, ultrasonic, magnetic particle, radiography, and dye penetrant, as appropriate. The data is analyzed to assure the pipeline is structurally sound and fit-for-service. If the pipeline is not structurally sound, an engineering design package is prepared to initiate, complete and document the work action. Management of Change and other procedures are applied as required.

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GPB Section D

Corrosion Monitoring and Inspection Goals

Section D GPB Corrosion Monitoring and Inspection Goals

Section D.1 2009 Corrosion and Inspection Goals Reviewed

The corrosion inspection, monitoring and mitigation programs were expected to be substantially unchanged from the previous year. In particular, the general and pitting corrosion control targets (<2 mpy and <20 mpy, respectively) remained in place with monitoring activity levels approximately the same as for recent years.

Section D.1.1 Corrosion Monitoring

The weight loss coupon installation and removal frequency remained essentially unchanged in 2009 as compared to recent years and is summarized in GPB Table D.1. The weight loss coupon program is undergoing schedule optimization as planned and began transitioning to a uniform 4 month exposure period for all services except produced water towards the end of 2009.

Service	Flow Lines (months)	Well Lines (months)
3-phase production	3	4
Produced water	6	8
Seawater	3	3
Processed Oil	3	N/A

GPB Table D.1 Coupon Pull Frequency

The activity level from the weight loss coupon program was anticipated to be similar in 2009 as that in 2008, and indeed this was the case. A substantial number of coupons pulled near the end of the year were still being analyzed at the time this report was prepared.

The ER probe program was planned to be substantially the same as in 2008 with probes being strategically located on the 3-phase production lines. The 2009 activity was largely as anticipated, however 18 additional probe monitoring locations were added - further improving the ability to monitor short term trends in fluid corrosivity.

Section D.1.2 Inspection Programs

The fundamental elements of the Inspection Programs outlined in Appendix 3.3.3 (CRM, ERM, FIP, CIP and CUI) form the foundation for the inspection program.

In 2009, twenty-eight ILI runs were performed on GPB pipelines - nearly twice the number of ILI runs performed in 2008; exceeding the 20 ILI runs targeted for 2009.

External corrosion inspection activity in 2009 was essentially double the level of activity in 2008. A historical high level of 90,000 inspections was planned in 2009, of which 90,404 were completed.

A total of 21,988 internal inspections were performed in 2009; 29,000 inspections were planned.

The long-term management strategy was continued for cased piping segments consisting of repeat inspections and excavation. The target was 200 cased segments; 524 segments were inspected using a combination of techniques. In addition thirteen casing excavation inspections were completed.

Section D.1.3 Chemical Optimization

There were no large-scale changes forecast for the corrosion mitigation program in 2009 and this proved to be the case.

Section D.1.4 Program Reviews

Subsequent to the oil transit line events of 2006, several reviews of the corrosion program were conducted with stakeholders (e.g. State, Federal, and Working Interest Owners). The substantial volume of input received as a result of these stakeholder discussions and reviews continues to be analyzed and integrated.

Section D.1.5 Corrective Actions

This section summarizes the corrective actions taken on cross-country flow lines as a result of corrosion monitoring and inspection results exceeding the specified targets. These targets are detailed in Appendix 3.1.3.

GPB Table D.2 notes the corrective mitigation actions taken as a result of inspection information. Inspection increases are evaluated using monitoring, mitigation, inspection and operational data. In some cases, the corrective action may be to "watch" the data set for validation of a potential increasing corrosion rate trend. Inspection increases listed here represent data from individual inspection points on a pipeline and therefore are not immediately considered to indicate an integrity threat prior to reviewing other inspection data for the entire pipeline.

Equipment ID	No. of Action	Cause	Action
F-74	1	Inspection Increase	Watch
S-69	1	Inspection Increase	Watch - Evaluating CI change
Z-74	1	Inspection Increase	Watch - Review maintenance pigging schedule change
LPC-SWI	1	Inspection Increase	Watch
16-SWI	1	Inspection Increase	Watch - Replace ER probe
17-SWI	1	Inspection Increase	Improve CI delivery

GPB Table D.2 Corrective Mitigation Actions from Inspection Data

GPB Table D.3 notes the corrective mitigation actions taken as a result of ER probe readings exceeding target.

Equipment ID	No. of Action	Cause	Action
P-36	1	Increased Corrosivity	Increased CI by 25%
Y-36	1	Increased Corrosivity	Addressed by P-36 CI increase
A-74	1	Increased Corrosivity	Increased CI by 25% (test pad)

GPB Table D.3 Corrective Mitigation Actions from ER Probe Data

GPB Table D.4 notes the corrective mitigation actions taken as a result of weight loss coupons exceeding target.

Equipment ID	WLC CR mpy	Cause	Action
STP/SIP-40	2.3 2.3	Increased Corrosivity	Improve delivery of biocide treatment program and oxygen scavenging at STP

GPB Table D.4 Corrective Mitigation Actions from Coupon Data

Section D.2 2010 Corrosion Management Goals

Overall, the 2010 corrosion and inspection goals will be focused on the continued delivery and optimization of current programs.

Section D.2.1 Corrosion Monitoring

Optimization of weight loss coupon scheduling will move towards completion in 2010, with the transition to four month coupon exposures for all service types except produced water. Additional monitoring methods will continue to be investigated for the PW system in an effort to develop a more sensitive short-term monitoring tool.

Section D.2.2 Chemical Optimization and Maintenance Pigging

Corrosion inhibition will continue to be the primary means of internal corrosion control at GPB. Supplemental corrosion inhibition of the PW system will continue. For the 3-phase system, the emphasis will be on the optimization of corrosion inhibitor and providing improved control. Corrosion inhibitor evaluation using rapid screen tests will continue to be performed throughout the year as products are developed.

Continuous improvement of maintenance pigging programs is expected in 2010, as the pigging frequency and efficacy are optimized. Management of the maintenance pigging schedule and the operations reporting mechanism also continues to undergo review and improvement.

Section D.2.3 Inspection Programs

The 2010 internal inspection program for cross country flow lines and well lines is expected to be 27,000 inspections, which represents approximately 45% of the total internal inspection program.

The external inspection program target is 90,000 inspections.

The long-term management strategy for cased piping segments will continue; consisting of repeat examinations and excavations as warranted. The work scope for cased piping is scheduled to be approximately 400 inspections.

The ILI program target is 20 pipelines but delivery will be dependant upon tool and pipeline availability.

The Walking Speed Survey program will continue as scheduled for the GPB West Well Pads.

Part 5 – Alaska Consolidated Team Business Unit

ACT Section A

Corrosion Monitoring and Mitigation

Section A ACT Corrosion Monitoring and Mitigation

Section A.1 Endicott

Section A.1.1 Monitoring

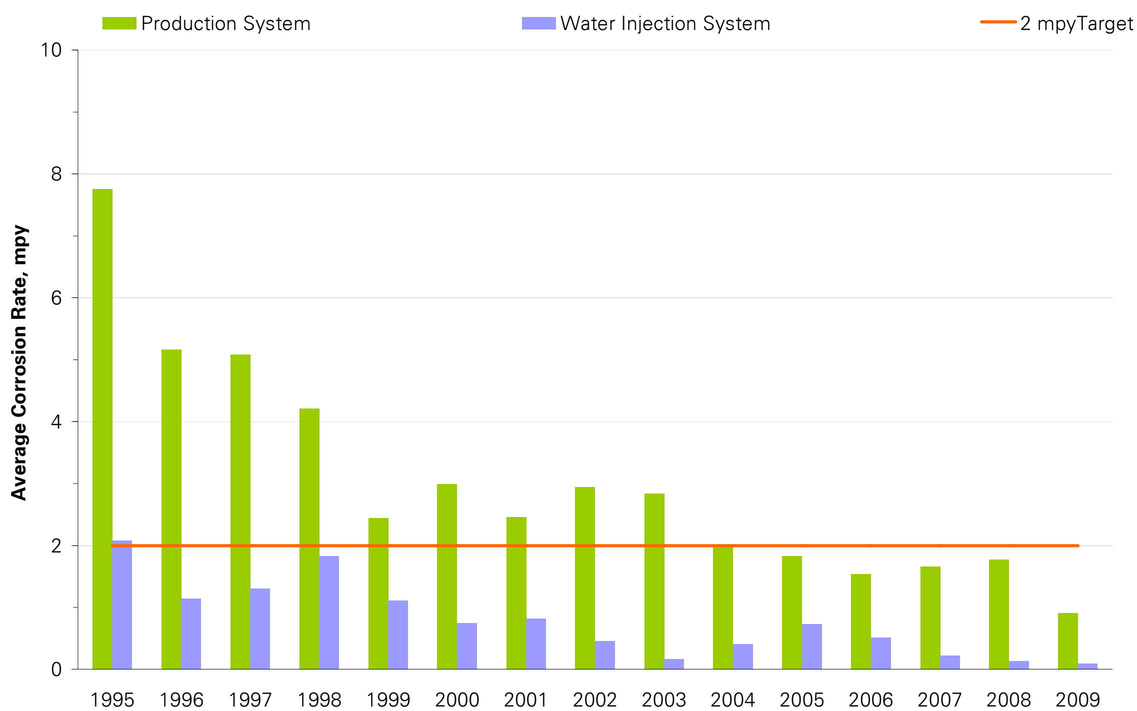
ACT Table A.1 summarizes the Endicott corrosion monitoring performance. Historical data is shown in ACT Figure A.1.

The average WLC corrosion rate for the production system remains near 2 mpy. Since the major portion of the system is fabricated from duplex stainless steel the data is used primarily for monitoring produced fluid corrosivity and erosion tendency. The data also assists in determining the corrosion susceptibility of the carbon steel C-Spools connecting the wellhead to the well line.

The lower, relatively constant corrosion rates in the water injection system reflect the effectiveness of the corrosion mitigation program. No water injection WLC experienced corrosion rates above the 2 mpy target; consistent with ER probe results.

System	Access Fittings	%WLC <2 mpy
Water Injection - Pads	15	100%
Water Injection – x-country	1	100%
Oil Production – Pads	71	84% (DSS)

ACT Table A.1 Endicott Corrosion Coupon Monitoring



ACT Figure A.1 Endicott Corrosion Coupon Summary

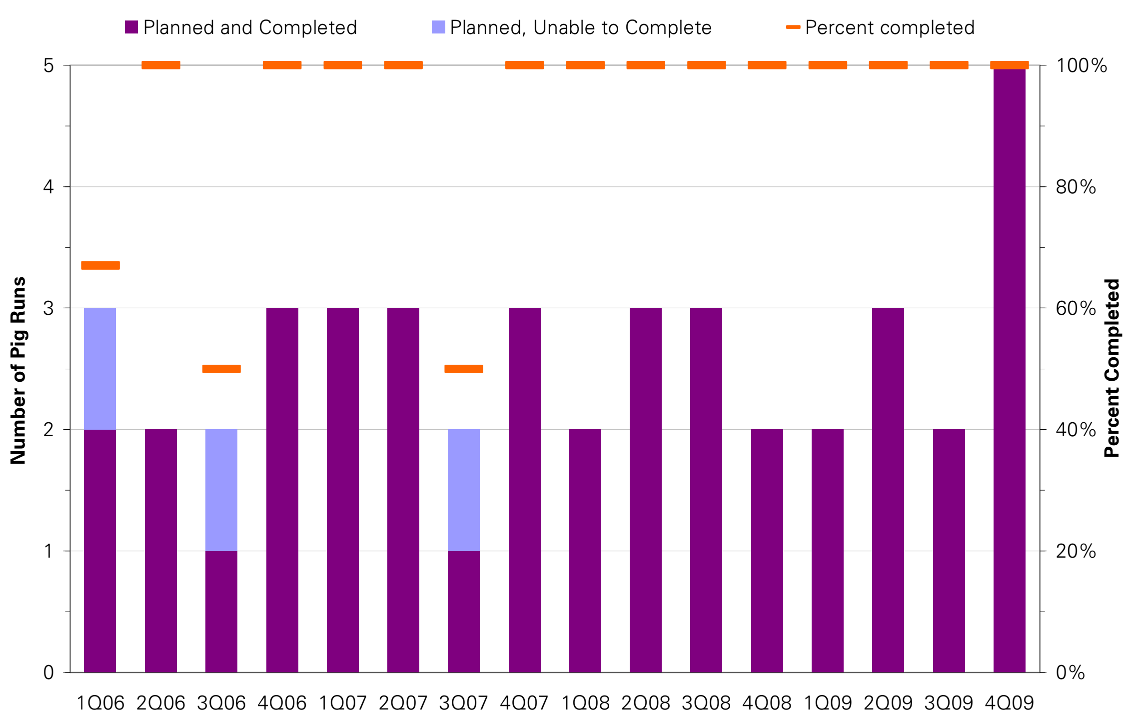
Section A.1.2 Mitigation

The primary internal corrosion concerns are in the water injection system, mainly the Inter-Island Water Line (IIWL) carrying injection water to SDI from the MPI. Corrosion control of the water injection system relies on corrosion inhibition of the injection water, supplemented by a periodic biocide treatment and maintenance pigging program. Originally, this line carried seawater. In the early 1990's, in an effort to increase waterflood efficiency, the line was converted to commingled PW+SW service. As produced water volumes have risen, SW usage has diminished and is no longer used for injection purposes. In response to internal corrosion inspection increases in early 2008, the continuous corrosion inhibitor treatment was increased from 30 to 40 ppm.

The annual target volume for produced water corrosion inhibitor at Endicott was 105,377 gallons; the actual volume of CI used was 111,999 gallons. The annual average CI concentration was 41 ppm, which met the target concentration for the year.

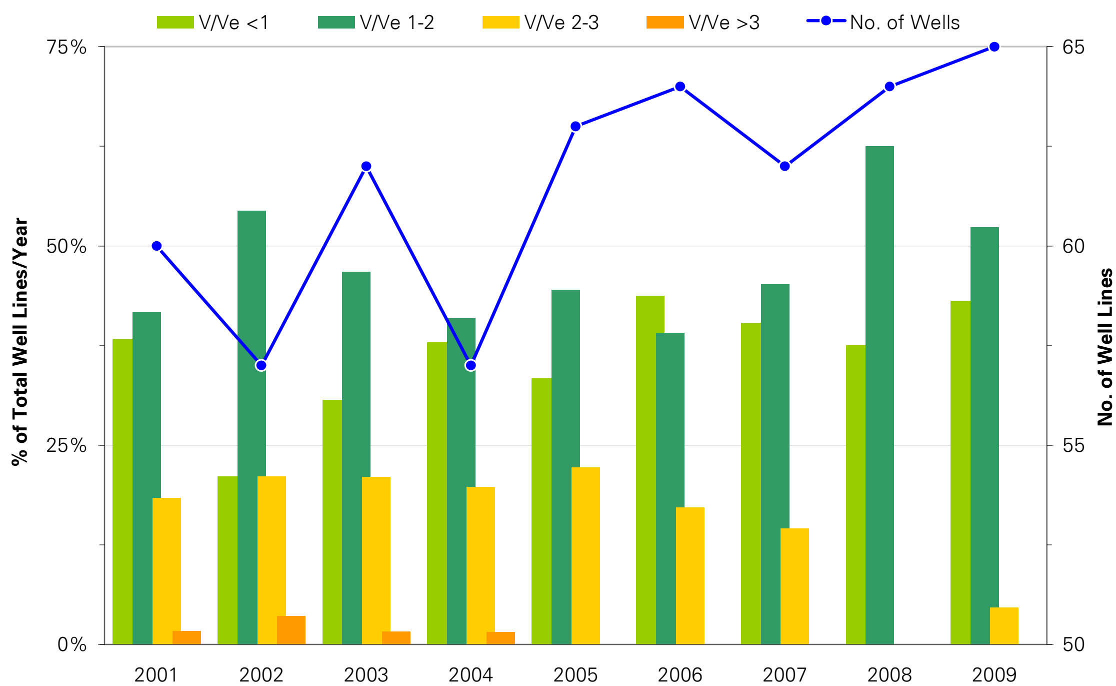
Corrosion mitigation for the IIWL has also relied on maintenance pigging for line cleanliness, biocide treatments to control bacterial activity and continuous injection of a corrosion inhibitor for corrosion control.

Maintenance pigging of the Endicott IIWL has been scheduled on a five-week interval. ACT Figure A.2 shows the delivery performance for the IIWL pigging by quarter beginning in 2006. In 2009, 100% of the maintenance pig runs were completed as scheduled. In addition, improvements in the maintenance pigging program were made in 4Q09 to increase the effectiveness of cleaning during the pig run and increase the frequency of pigging.



ACT Figure A.2 Endicott IIWL Maintenance Pigging Performance

In the production system, the primary damage mechanism is erosion in the duplex stainless steel sections and corrosion in the carbon steel C-Spool sections. The erosion rate is monitored through inspection and mitigated through velocity management. Wells are risk-ranked monthly based on mixture velocity and the velocity information is used to adjust the inspection frequency and fluid velocity. ACT Figure A.3 is an overview of the average velocity data since 2001. Shown are the percent of wells within various V/V_e ratio ranges, where V is the actual mixture velocity, V_e is the velocity at which erosion becomes a concern as defined by API-RP-14E[10] and V/V_e is the erosion velocity ratio.



ACT Figure A.3 Endicott Velocity Monitoring

API Recommended Practice 14E defines an allowable velocity for the avoidance of erosion, based on the fluid properties including density and material of construction. API 14E is known to be conservative when applied to oil production systems, particularly where corrosion and erosion resistant materials are used. The aim is to limit actual velocities to less than 2.5 times the allowable velocity (V/V_e <2.5) which reflects BPXA's experience with production fluids that contain minimal amounts of entrained solids. Equipment exhibiting high velocities is inspected at intervals ranging from weekly to bi-annually dependant upon the V/V_e ratio, input from Well Operations, and inspection results. The V/V_e data for 2009 were largely comparable to the previous year, with more wells reporting V/V_e <1. Although no twelve month average exceeded V/V_e >2.2; inspection increases related to erosion were investigated. Where necessary, further reductions in velocity were made by reducing production.

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[10] API-RP-14E - Recommended Practice for Design and Installation of Offshore Production Platform Piping System 5th Edition.

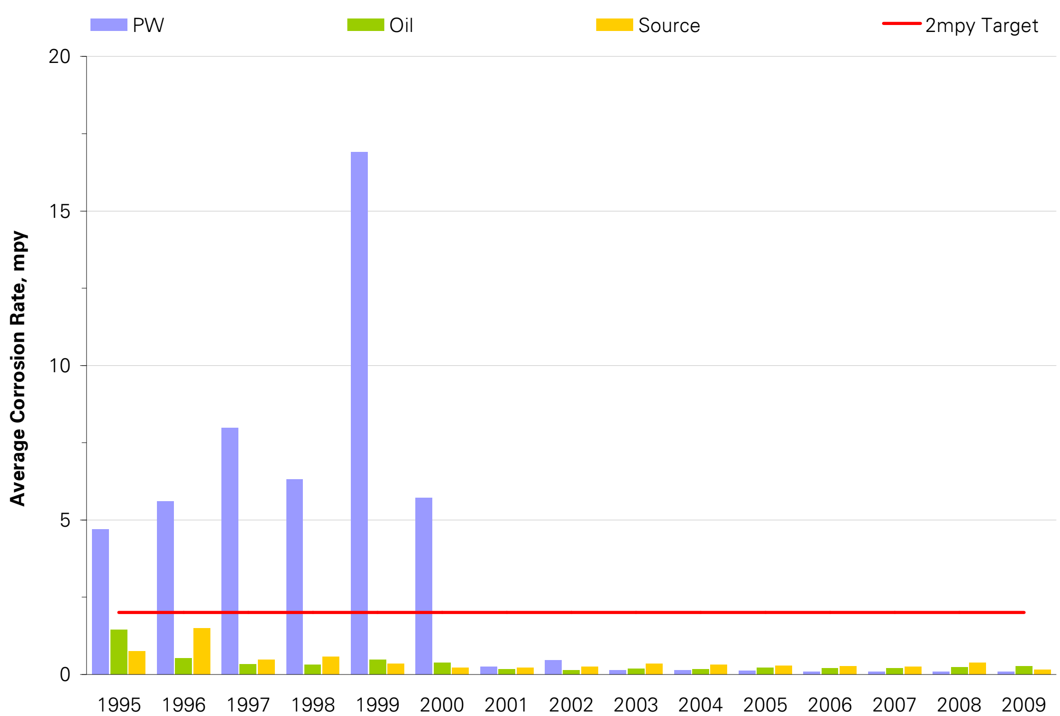
Section A.2 Milne Point

Section A.2.1 Monitoring

ACT Table A.2 summarizes the Milne Point Unit corrosion monitoring performance for 2009 and historical data is shown in ACT Figure A.4 which illustrates the low corrosion rates for the MPU production and water systems. Of concern historically were the relatively higher corrosion rates in the water injection system. These higher corrosion rates led to the initiation of corrosion inhibition in the water injection system in mid-2000. The monitoring results indicate the inhibition has been successful in reducing the corrosion rate, as the water injection WLC corrosion rates have consistently averaged <2 mpy. Three WLCs in production wells exceeded the 2 mpy target.

System	Access Fittings	%WLC <2 mpy
Production System	26	97%
Water Injection System	4	100%
Source Water Coupons	3	100%

ACT Table A.2 MPU Corrosion Coupon Monitoring



ACT Figure A.4 MPU Corrosion Coupon Summary

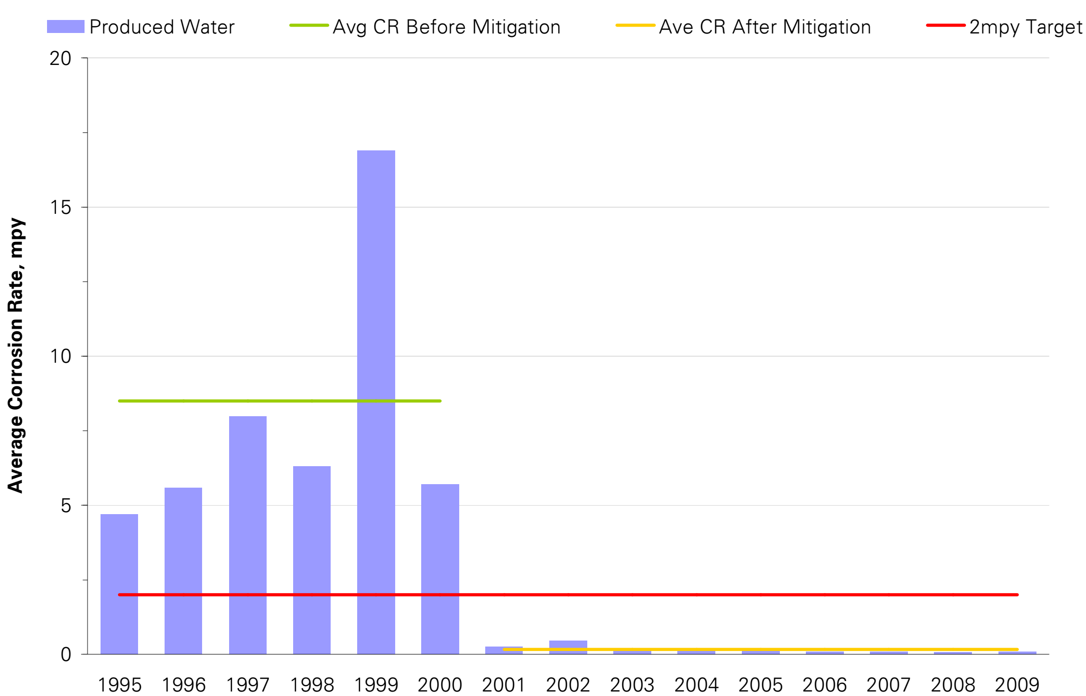
There were seven ER probes used for corrosion monitoring of flow lines at Milne Point and one new ER probe was added to the oil export line in December 2009. No mitigation actions were required to address corrosion rate exceptions at Milne. Good correlation has been observed between WLC and ER probe data.

Section A.2.2 Mitigation

Corrosion inhibition of the water injection system began in mid-2000. In addition, a more rigorous maintenance pigging program was implemented. Weight loss coupon data indicate the system is under control as the WLC corrosion rates have averaged less than 2 mpy since mid-2000. This represents a significant reduction from previous years as can be seen in ACT Figure A.5. For the period 1996-2000, the average corrosion rate was approximately 7 mpy. Since the enhancement of the corrosion management program in 2000, the average WLC corrosion rate for the PW system has been reduced to less than 1 mpy. As a result of a trial of a new corrosion inhibitor, the inhibitor concentration was increased in 2007 from 40 ppm to 55 ppm as well as eliminating the biocide regime.

The annual corrosion inhibitor target volume for 3-phase production was 117,360 gallons; the actual volume of CI used was 115,484 gallons. The annual average CI target concentration for 3-phase production at Milne was 103 ppm; the annual average delivered concentration was 102 ppm.

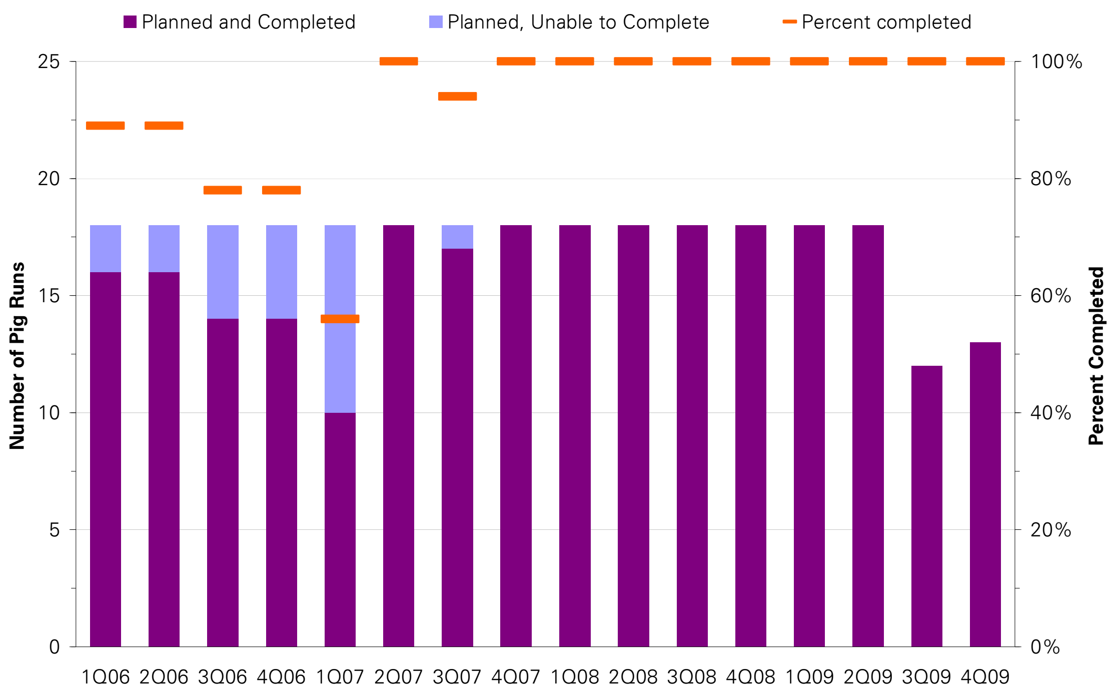
The annual corrosion inhibitor target volume for produced water was 73,520 gallons and the actual volume of CI used was 73,504 gallons. The annual average CI target concentration for produced water was 55 ppm; the annual average delivered concentration was 57 ppm.



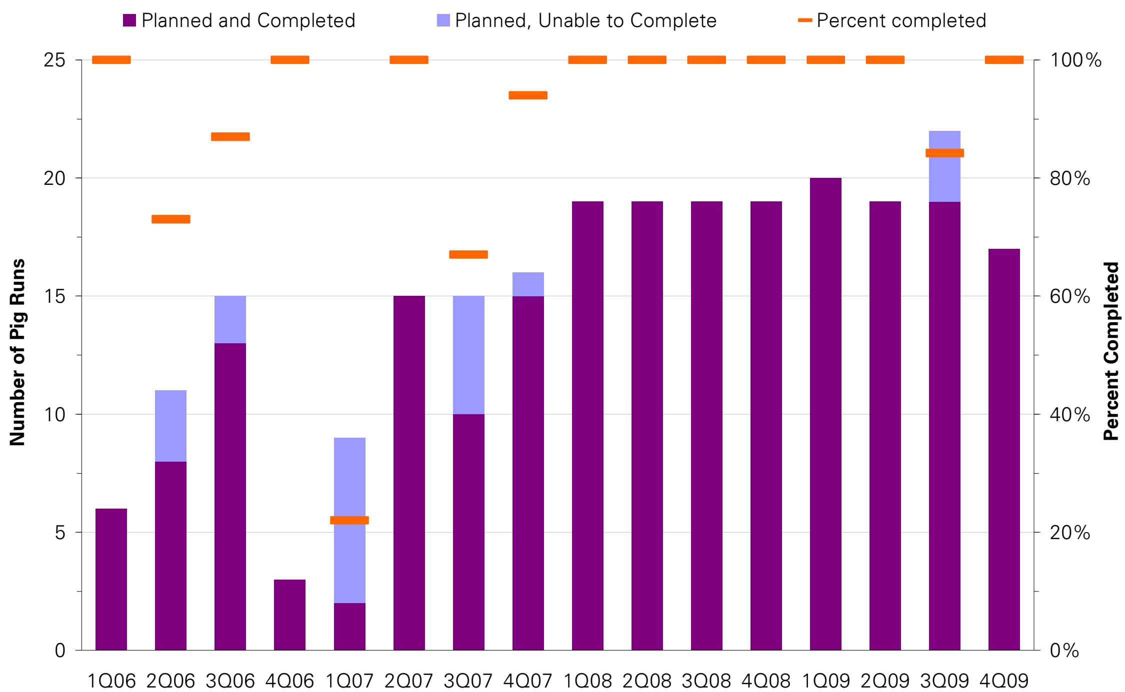
ACT Figure A.5 Milne Point Produced Water Corrosion Rate Trend

Although the low temperatures and low CO_2 content of the production fluids result in lower corrosivity for MPU than in other areas, solids contribute to the corrosion mechanism of the production system. As production rates are typically low for the pipeline capacity, the fluid velocities are low and erosion is not a significant concern, therefore there currently is no formal velocity management program.

The quarterly maintenance pigging performance results for the MPU produced water lines and the 3-phase lines are shown in ACT Figure A.6 and ACT Figure A.7 respectively, for the years 2006-2009. One hundred percent of the maintenance pig runs in the produced water lines were completed on-schedule in 2009 and ninety-six percent of the maintenance pig runs in 3-phase lines were completed on schedule.



ACT Figure A.6 MPU PW Maintenance Pigging Performance



ACT Figure A.7 MPU 3-phase Maintenance Pigging Performance

Section A.3 Northstar

Section A.3.1 Monitoring

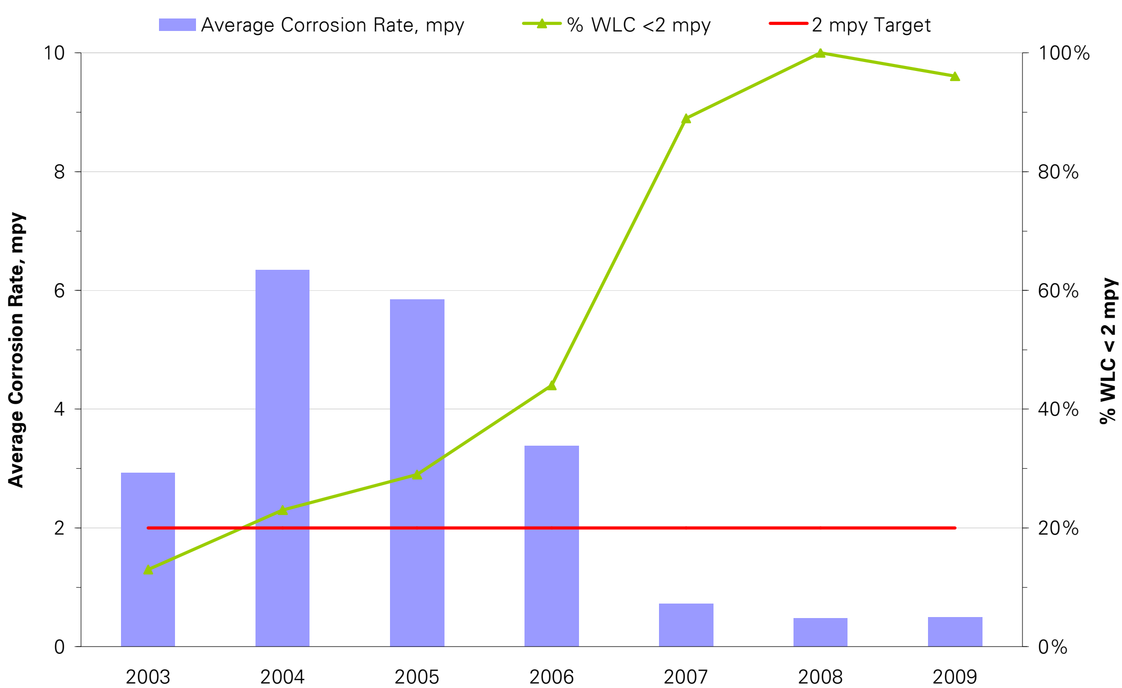
ACT Table A.3 shows the results of the corrosion monitoring program at Northstar for 2009. ACT Figure A.8 shows the historical WLC performance for the three phase system.

System	Location	Access Fittings	%WLC <2 mpy
Oil Production		19	96%
Water Disposal			
	Upstream of Disposal Facility	9	100%
	Downstream of Disposal Facility	2	75%

ACT Table A.3 Northstar Corrosion Coupon Monitoring

In addition to the weight loss coupon data, an electrical resistance probe is installed on the main production flow line to provide information on short term corrosion trends. The probe data is useful in correlating corrosion rate excursions to corrosion inhibitor injection rates and other operating conditions. Occasional excursions above 2 mpy have been observed during ongoing corrosion inhibitor rate optimization at the wells, however all excursions are analyzed to determine if the proper amount of inhibitor is being applied.

Corrosion rate exceptions previously experienced by WLC in one of the water disposal wells was attributed to handling oxygenated mud from the grind-and-inject plant (mud) during drilling operations and oxygenated fluids from the sewage treatment facility. Disposal well coupons indicated an average general corrosion rate of 1.6 mpy which is significantly improved over the average general corrosion rate of 3.8 mpy in 2008. This system is also being inspected on a quarterly basis to monitor for active metal loss.



ACT Figure A.8 Northstar 3-Phase Oil Corrosion Rate Trend

Section A.3.2 Mitigation

Northstar began production in November 2001. Production fluid corrosivity is moderate, but has been increasing over time with the injection of higher CO_2 content GPB gas into the reservoir for pressure maintenance purposes.

Northstar performs continuous injection of corrosion inhibitor into the well production lines. As of the end of 2007, all wells have had the chemical injection location moved upstream to the wellhead assuring all portions of the carbon steel well line are now inhibited.

In 2009, the annual target volume for 3-phase production corrosion inhibitor at Northstar was 37,733 gallons; the actual volume of CI used was 37,874 gallons. The target concentration was 165 ppm; the annual average CI concentration was 167 ppm.

Section A.4 Badami

Section A.4.1 Monitoring

Badami currently has no WLC-monitoring program, and relies on the inspection program presented in Section B.4 to provide corrosion control feedback.

Section A.4.2 Mitigation

Production from the Badami field began in 1998, however low production necessitated periods of shut-in of the field from the third quarter of 2003 throughout all of 2004 and beginning again in the summer of 2007. Shut-ins consist of de-inventory and warm storage of major equipment. During production periods, Badami's production fluids are considered low corrosivity, as there is little water production and very low CO_2 content. Startup and periodic inspections were performed on existing equipment during the shut in periods.

ACT Section B

External/Internal Inspection

Section B ACT External/Internal Inspection

Section B.1 Endicott

The duplex stainless steel well lines are subject to erosion and are monitored through a velocity monitoring and inspection program. In the oil production system, the only carbon steel is the C-Spool, connecting the wellhead to the duplex stainless steel well line. These C-Spools are inspected regularly and replaced with DSS when no longer fit-for-service as per the criteria discussed in Appendix 3.3.5. Nine carbon steel C-spools were replaced with DSS in 2009. ACT Table B.1 reflects the historical inspection activity level for Endicott since 2002.

Service	Length miles	Year	2002	2003	2004	2005	2006	2007	2008	2009
Oil X-country lines	3.5	External	-	-	-	-	-	-	-	-
		Internal	4	14	4	14	40	-	43	68
		Total	4	14	4	14	40	-	43	68
Oil Pipe Rack	0.3	External	-	-	-	-	-	-	-	-
		Internal	19	6	-	20	-	2	35	32
		Total	19	6	-	20	-	2	35	32
Oil - Well Pads	2.5	External	-	-	-	-	-	-	-	-
		Internal	1,304	1,540	1,900	2,653	2,933	3,047	4,002	3,919
		Total	1,304	1,540	1,900	2,653	2,933	3,047	4,002	3,919
Water X-country lines	3.5	External	-	-	719	30	11	8	-	6
		Internal	104	229	163	119	136	216	172	331
		Total	104	229	882	149	147	224	172	337
[1] Water Pipe Rack	0.3	External	-	-	4	-	-	-	-	94
		Internal	27	26	227	269	43	63	396	60
		Total	27	26	231	269	43	63	396	154
[1] Water - Well Pads	1.7	External	-	2	-	8	-	-	11	-
		Internal	210	221	128	312	321	217	223	282
		Total	210	223	128	320	321	217	234	282
Gas X-country (GLT/MI)	7	External	-	752	-	34	13	1	66	829
		Internal	15	45	4	12	53	-	120	57
		Total	15	797	4	46	66	1	186	886
Gas Pipe Rack	0.3	External	-	22	-	265	-	221	5	431
		Internal	24	23	-	-	-	-	28	51
		Total	24	45	-	265	-	221	33	482
Gas - Well Pads	1.2	External	-	24	-	28	-	879	4	1
		Internal	26	27	10	61	41	34	28	32
		Total	26	51	10	89	41	913	32	33
Total External			**-**	**800**	**723**	**365**	**24**	**1,109**	**86**	**1,361**
Total Internal			**1,733**	**2,131**	**2,436**	**3,460**	**3,567**	**3,579**	**5,047**	**4,832**
Total, All Inspections			**1,733**	**2,931**	**3,159**	**3,825**	**3,591**	**4,688**	**5,133**	**6,193**

[1] Water Alternating Gas (WAG) counted with water injection system.

ACT Table B.1 Endicott Summary of Lines and NDE Inspections

Section B.1.1 External Inspection

The external inspection program consisted of 1,361 inspections with the majority being on gas transit and pipe rack lines. Three percent of the inspections were observed to have increases in metal loss as compared to the prior inspection

Cased flow and well lines at Endicott are inspected at the intervals noted in ACT Table B.2. In addition, the vaults where the 3-phase oil and processed oil flow lines pass are visually inspected annually. Permanent LRGWUT sensors were installed on the MI line at the MPI/SDI road intersection in 2008. The gas well line to Endeavor Island (listed in Table B.2 previous reports) last surveyed with LRGWUT in 2000, was moved above grade in 2006.

Line	Crossings	Year Surveyed	Method	Max Inspection Interval
Water - Inter-Island	1	Crossing replaced in 2007	LRGWUT	5 Years
Gas Lift - Inter-Island	1	Crossing replaced in 2007	LRGWUT	5 Years
Oil	1	N/A	N/A	Duplex Stainless Steel
MI Line	1	2009	LRGWUT	5 Years
Water – WL	2	1 line in 2000	LRGWUT	5 Years for Carbon Steel - Other line is Duplex Stainless Steel

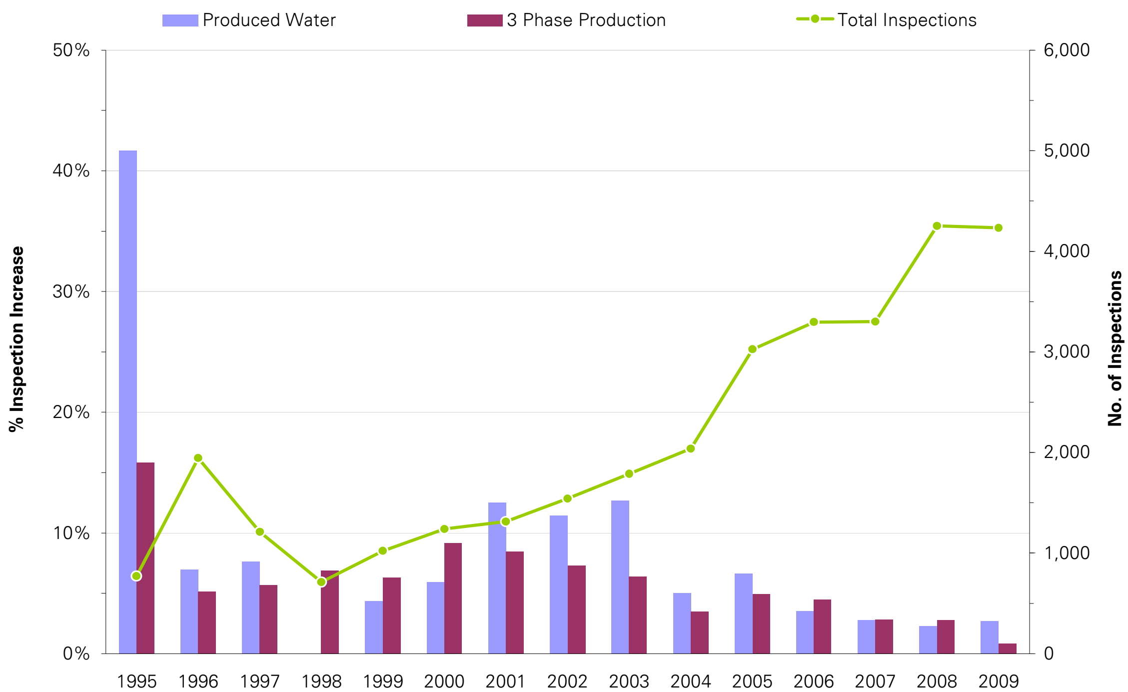
ACT Table B.2 Cased Piping Inspections

Section B.1.2 Internal Inspection

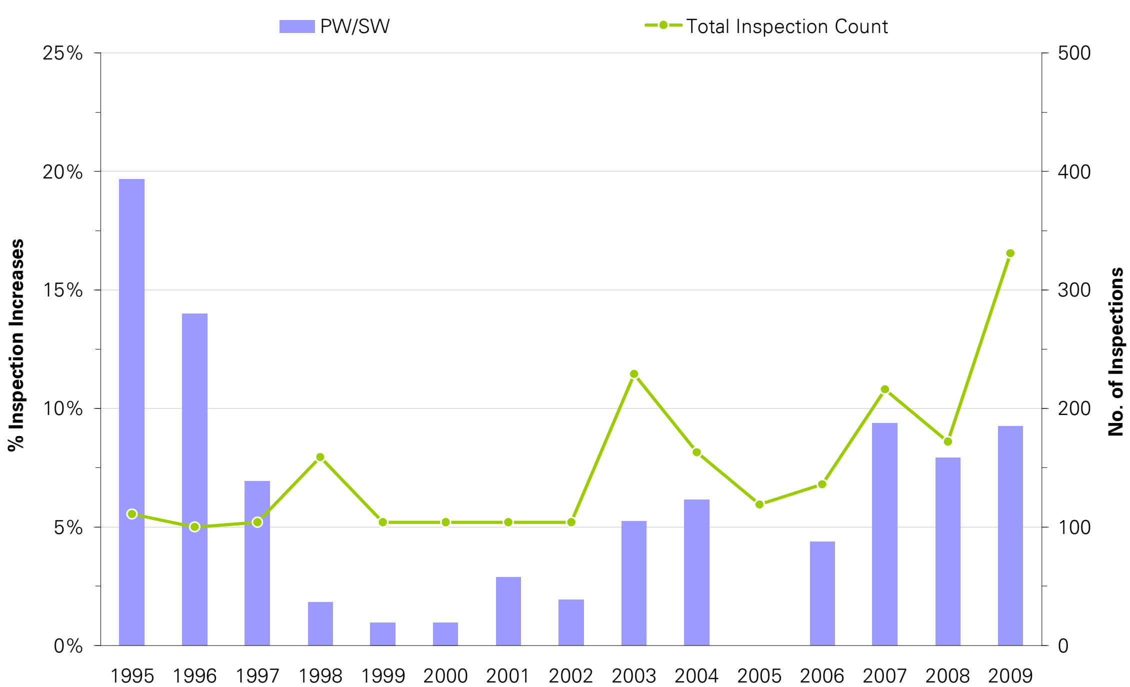
ACT Figure B.1 and ACT Figure B.2 indicate the percentage of inspection increases since 1995 for the well lines and flow lines at Endicott. The inspection data for the 3-phase production system are used to guide Operations in future potential replacements of the carbon steel C-Spools at the wellheads. In 2007, replacement of the carbon steel C-Spools with duplex stainless steel spools began on an as-needed basis.

Corrosion activity in the water injection well lines as shown in ACT Figure B.1 had been addressed by increasing the corrosion inhibitor concentration in 2003 and again in 2004. In 2009 only 3% of the inspections showed increases in metal loss as compared to 13% in 2003.

ACT Figure B.2 shows the percentage of inspection increases and total number of internal inspections from 1996 through 2009 for the IIWL at Endicott. The data represent all inspections performed on the line regardless of reinspection interval. However, determining short term corrosion trends or mitigation performance from long reinspection intervals can be difficult.

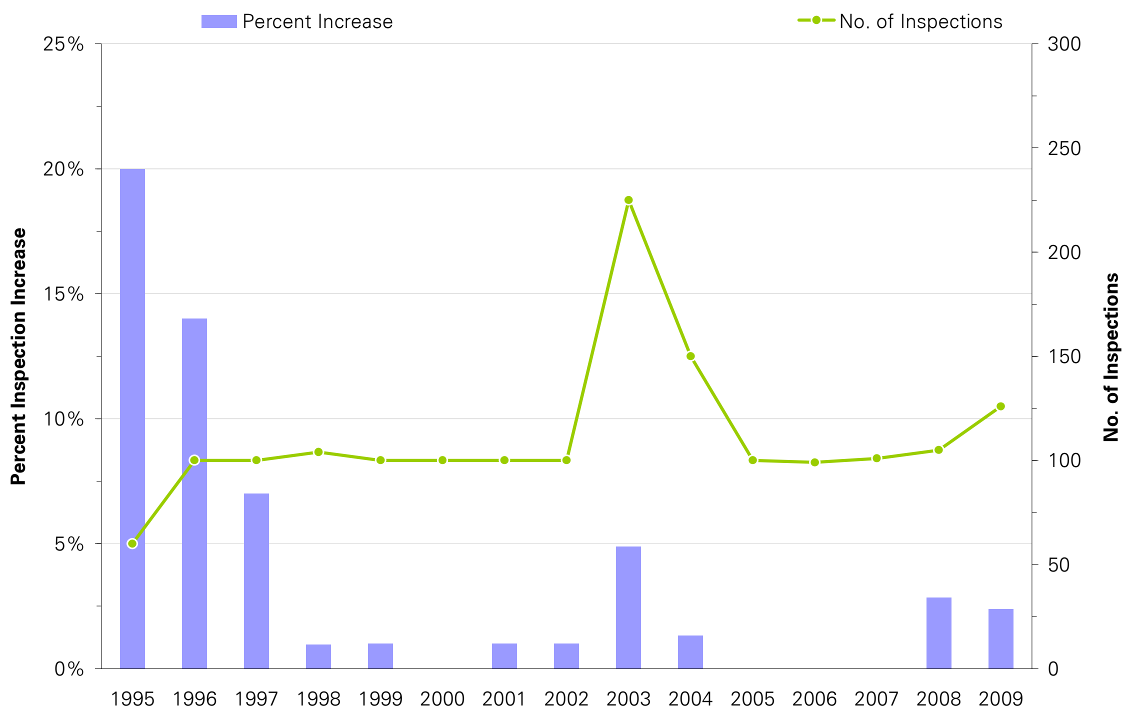


ACT Figure B.1 Endicott Well Line Internal Inspection Increases



ACT Figure B.2 Endicott IIWL Internal Inspection Increases

A more accurate representation of corrosion activity for the IIWL through time is shown in ACT Figure B.3 which includes only data from inspections performed on a frequent basis since 1995. The frequently monitored locations show a decrease in corrosion activity during 2004, and no inspection increases during 2005-2007. In 2009, only 2% of the frequently inspected locations showed inspection increases. The improvement may have resulted from adjustments to the maintenance pigging program made early in 2009, however the data will continue to be evaluated to ensure continued long term improvement.



ACT Figure B.3 Endicott IIWL Frequent Inspection Results

Section B.2 Milne Point

BPXA became operator at Milne Point in 1994, and from 1994 to 2000 the inspection program was aimed at establishing the baseline condition of the MPU systems. It is only with the 2000 data and beyond that trending of inspection increases has been possible. ACT Table B.3 reflects the historical inspection activity for MPU since 2002.

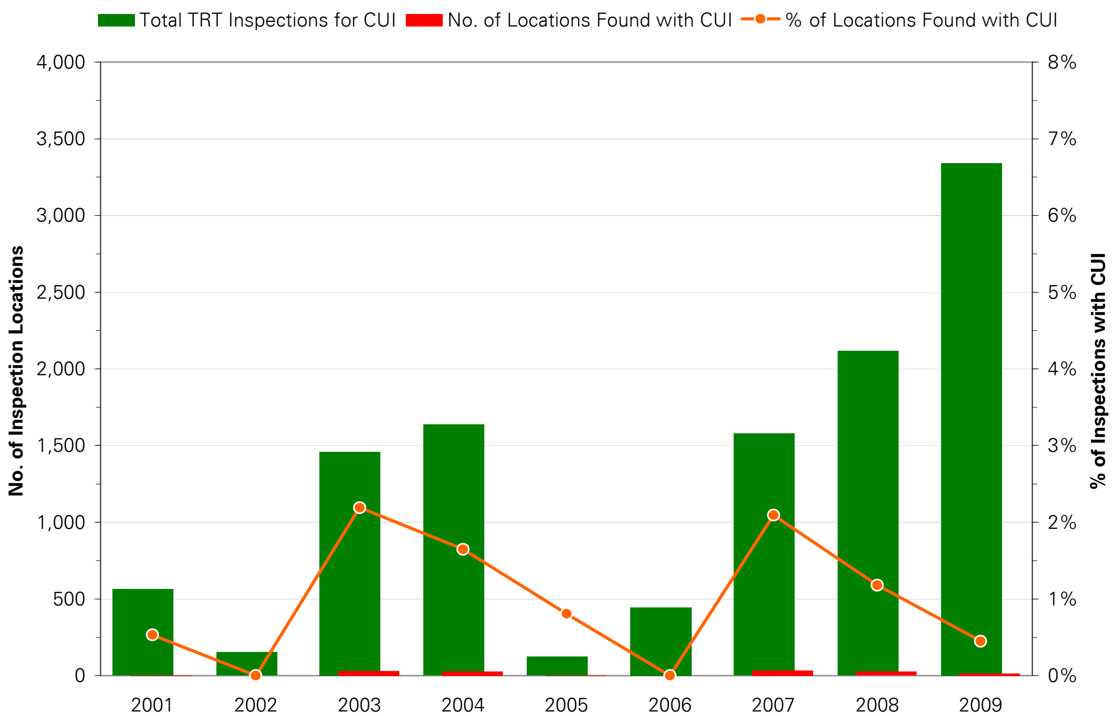
Service	Length miles	Year	2002	2003	2004	2005	2006	2007	2008	2009
Oil X-country lines	24	External	-	912	65	-	74	1,247	534	336
		Internal	134	462	485	182	836	1,452	470	329
		Total	134	1,374	550	182	910	2,699	1,004	665
Oil - Well Pads	N/A[1]	External	62	-	-	5	4	65	229	1,206
		Internal	755	2,725	2,052	2,012	1,961	1,557	1,772	1,783
		Total	817	2,725	2,052	2,017	1,965	1,622	2,001	2,989
Water X-country lines	15	External	-	71	997	133	35	149	827	627
		Internal	37	195	258	53	121	1,435	523	578
		Total	37	266	1,255	186	156	1,584	1,350	1,205
Water - Well Pads	N/A[1]	External	35	-	-	3	1	49	115	534
		Internal	246	615	832	883	1,034	1,077	1,255	1,250
		Total	281	615	832	886	1,035	1,126	1,370	1,784
Gas X-country	14	External	-	486	594	-	449	478	601	234
		Internal	-	20	19	-	3	61	93	233
		Total	-	506	613	-	452	539	694	467
Gas - Well Pads	N/A[1]	External	56	-	-	-	-	921	100	432
		Internal	87	162	145	223	265	131	288	181
		Total	143	162	145	223	265	1,052	388	613
Water/Alternating Gas Well Pads	N/A[1]	External	-	-	-	-	-	-	-	-
		Internal	127	85	152	176	173	159	156	75
		Total	-	85	152	176	173	159	156	75
Total External			**153**	**1,469**	**1,656**	**141**	**563**	**2,909**	**2,406**	**3,369**
Total Internal			**1,386**	**4,264**	**3,943**	**3,529**	**4,393**	**5,872**	**4,557**	**4,429**
Total, All Inspections			**1,539**	**5,733**	**5,599**	**3,670**	**4,956**	**8,781**	**6,963**	**7,798**

[1] Totals not available
[2] Included with internal numbers as part of the excavations.

ACT Table B.3 MPU Summary of Lines and NDE Inspections

Section B.2.1 External Inspection

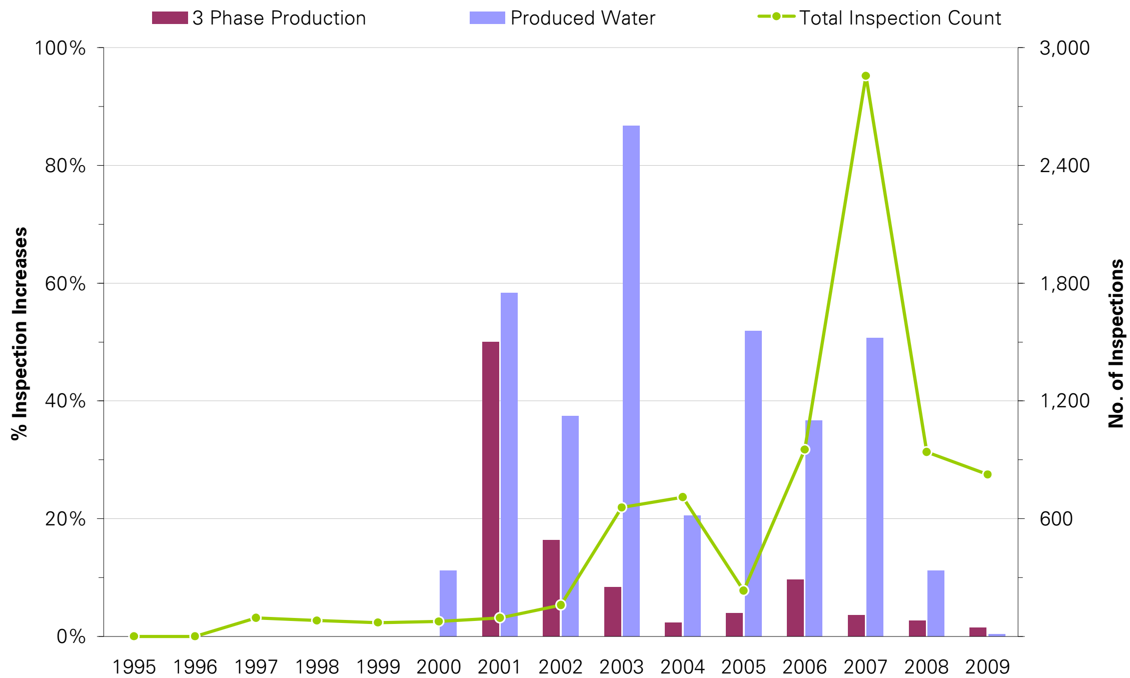
There were 3,369 external inspections performed at MPU in 2009. The MPU Tract 14 produced water and 3-phase flow lines were replaced with above grade piping that is equipped for maintenance pigging and ILI. Replacement of the buried pipelines has eliminated the need for frequent reinspection. Having removed from service the last of the buried pipelines, ACT Figure B.4 reflects the TRT detection activity and discovery of CUI on above grade piping only.



ACT Figure B.4 MPU Above Grade Piping External Inspection

Section B.2.2 Internal Inspection

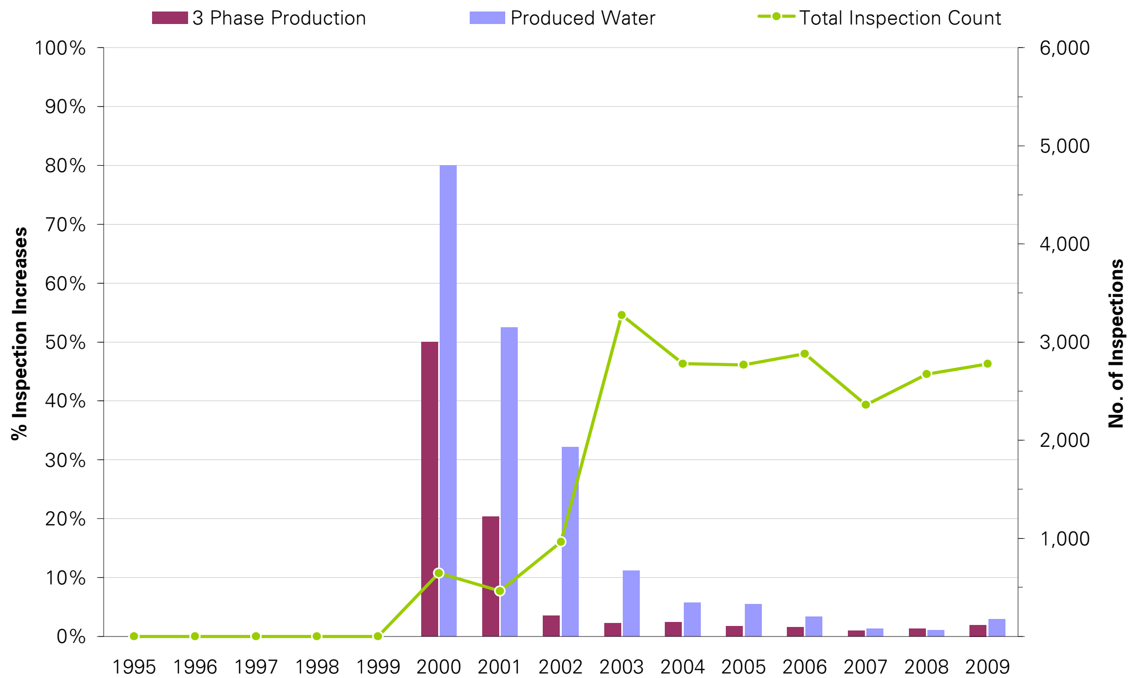
The results of the internal inspection program for flow lines are shown in ACT Figure B.5. Overall the 3-phase flow lines are continuing to show a decreasing trend of locations with corrosion activity. The produced water flow lines had no inspection increases in 2009 which is a substantial decrease from 11% in 2008. Overall, internal inspection results indicated a "best ever" performance for flow line inspection increases in 2009.



ACT Figure B.5 MPU Flow Line Internal Inspection Increases

ACT Figure B.6 shows the percentage of inspection increases and number of inspections on produced water and 3-phase well lines. Inspection activity has averaged 2,700 items per year for the last five years; 2,777 well line inspection were performed in 2009. The produced water well line and 3-phase well line damage rate continues to remain low, consistent with the performance of previous years

For source water well line lines, 4% of the 301 repeat inspections showed increases.



ACT Figure B.6 MPU Well Line Internal Inspection Increases

Section B.3 Northstar

ACT Table B.4 shows the historical inspection activity for Northstar since 2002.

Service	Length[2] feet	Year	2002	2003	2004	2005	2006	2007	2008	2009
Oil Pipe Rack	1,200	External	-	-	-	-	-	152	18	-
		Internal	-	-	10	-	14	150	65	45
		Total	-	-	10	-	14	302	83	45
Oil - Well Pad	280	External	-	-	-	-	-	-	-	-
		Internal	99	122	204	229	215	469	425	592
		Total	99	122	204	229	215	469	425	592
Water Pipe Rack[1]	2,400	External	-	-	-	-	-	34	-	3
		Internal	-	-	-	-	-	14	29	98
		Total	-	-	-	-	-	48	29	101
Water – Well Pad[1]	70	External	-	-	-	-	-	-	-	-
		Internal	17	25	46	52	34	79	75	80
		Total	17	25	46	52	34	79	75	80
Gas Pipe Rack	600	External	-	-	-	-	-	43	-	-
		Internal	-	-	-	-	-	19	30	47
		Total	-	-	-	-	-	62	30	47
Gas – Well Pad	140	External	-	-	-	-	-	-	-	-
		Internal	30	57	77	110	67	139	120	174
		Total	30	57	77	110	67	139	120	174
Total External			**-**	**-**	**-**	**-**	**-**	**229**	**18**	**3**
Total Internal			**146**	**204**	**337**	**391**	**330**	**870**	**744**	**1,036**
Total, All Inspections			**146**	**204**	**337**	**391**	**330**	**1,099**	**762**	**1,039**

[1] Disposal system; Northstar does not have an active water injection system.

[2] Line lengths are in feet as the production facility is contained in a comparatively small footprint.

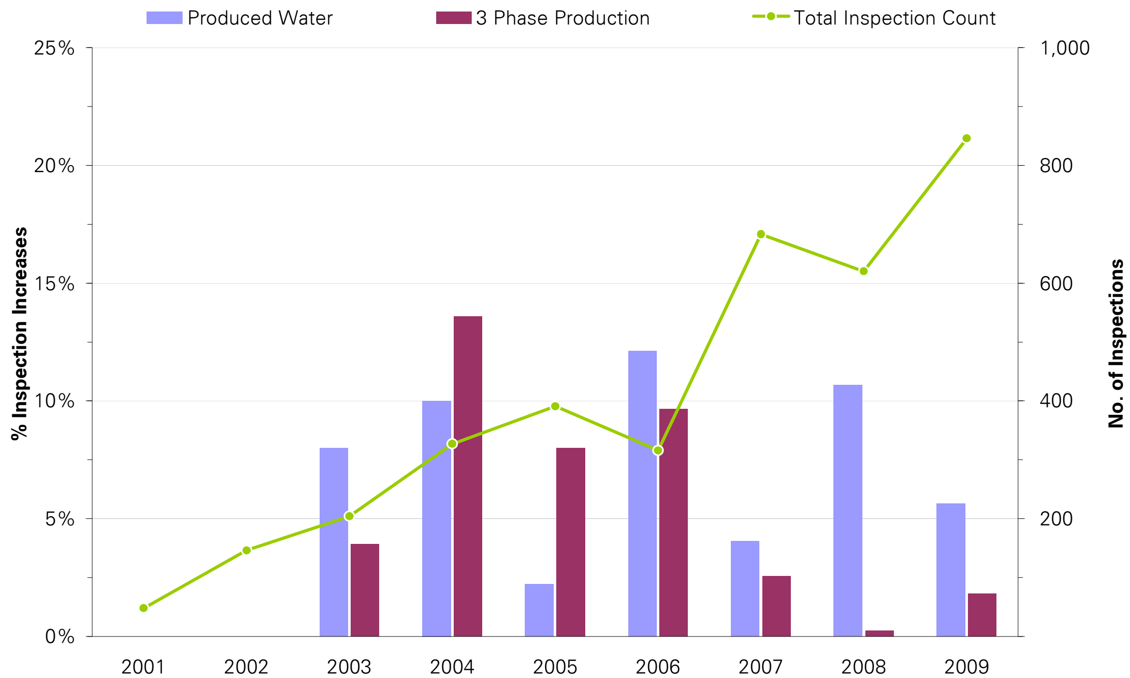
ACT Table B.4 Northstar Summary of Lines and NDE Inspections

Section B.3.1 External Inspection

Three external inspections were performed on produced water pipe rack lines at Northstar in 2009. One external inspection was at a repeat location and showed a slight inspection increase, while the other two locations were baseline inspections.

Section B.3.2 Internal Inspection

During 2009, a total of 846 well line inspections were completed on 3-phase, gas and water well line systems. The produced water disposal system showed a significant reduction in inspection increases from 11% in 2008 to 6% in 2009 (refer to ACT Figure B.7). Two percent of the inspections showed increases for the 3-phase well lines.



ACT Figure B.7 Northstar Well Line Internal Inspection Increases

Section B.4 Badami

The Badami Field was in warm shutdown from August of 2003 to October of 2005. Badami produced again until August of 2007, at which time it was placed back into warm shutdown. A post shutdown and follow up inspection was performed to monitor shut in status. Although the data set is limited, inspections support the overall assertion that Badami fluids have low corrosivity. This section summarizes the inspection program for Badami.

Section B.4.1 External Inspection

Five external inspections were performed on gas flow lines at Badami; all were baseline inspections.

Section B.4.2 Internal Inspection

ACT Table B.5 is a summary of well line inspections for Badami. There were 92 internal well line inspections; no inspection increases were observed.

Year	Oil	PW	Gas	Disposal	Total
2000	28	-	7	6	41
2001	-	-	-	-	-
2002	7	-	-	-	7
2003	37	-	7	3	47
2004	32	-	7	3	42
2005	34	-	3	4	41
2006	76	2	17	18	113
2007	50	2	56	10	118
2008	27	12	77	12	128
2009	27	20	45	-	92

ACT Table B.5 Internal Inspection Summary of Badami Well Lines

ACT Table B.6 ACT Inspection Summary summarizes the overall ACT inspection activity since 2000. A higher level of inspection activity continued in ACT during 2009.

Facility	Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Endicott	External	-	1	-	800	723	365	24	1,109	86	1,361
	Internal	1,350	1,449	1,733	2,131	2,436	3,460	3,567	3,580	5,047	4,832
	Total	1,350	1,450	1,733	2,931	3,159	3,825	3,591	4,689	5,133	6,193
Milne Point	External	118	598	153	1,469	1,656	141	563	2,909	2,406	3,369
	Internal	1,002	637	1,386	4,264	3,943	3,529	4,393	5,872	4,557	4,429
	Total	1,120	1,235	1,539	5,733	5,599	3,670	4,956	8,781	6,963	7,798
Northstar	External	-	-	-	-	-	-	-	229	18	3
	Internal	-	49	146	204	337	391	330	870	744	1,036
	Total	-	49	146	204	337	391	330	1,099	762	1,039
Badami	External	-	-	-	-	-	-	-	-	-	5
	Internal	41	-	7	47	42	41	113	118	128	92
	Total	41	-	7	47	42	41	113	118	128	97
Total External		**118**	**599**	**153**	**2,269**	**2,379**	**506**	**587**	**4,247**	**2,510**	**4,738**
Total Internal		**2,393**	**2,135**	**3,272**	**6,646**	**6,758**	**7,421**	**8,403**	**10,440**	**10,476**	**10,389**
Total, All Inspections		**2,511**	**2,734**	**3,425**	**8,915**	**9,137**	**7,927**	**8,990**	**14,687**	**12,986**	**15,127**

ACT Table B.6 ACT Inspection Summary

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ACT Section C

Corrosion and Structural Related Repairs and Spills

Section C ACT Corrosion & Structural Related Repairs and Spills

Section C.1 Repair Activities

ACT Table C.1 summarizes the repair activity for ACT. There were four repair locations identified for ACT; two of which were repairs at Endicott for external corrosion on yard piping (P) which are reported by exception. The other two repairs were on Milne Point produced water flow lines; one due to external corrosion and the other due to mechanical damage. There were no repairs at Northstar or Badami.

Service	Type	Internal	External	Mechanical
Oil	FL	-	-	-
	WL	-	-	-
	P	-	-	-
PW/SW	FL	-	1	1
	WL	-	-	-
		-	-	-
Gas	FL	-	-	-
	WL	-	-	-
	P	-	2	-
PO	FL	-	-	-
	P	-	-	-
	Total	-	3	1

ACT Table C.1 ACT Repair Activity

Section C.2 Corrosion and Structural Related Leaks

There were no corrosion related leaks in ACT in 2009. ACT Table C.2, ACT Table C.3, ACT Table C.4, and ACT Table C.5 summarize leak/save and mechanical repair data for Endicott, MPU, Northstar and Badami, respectively.

Service	Leaks	Saves
Oil x-country lines	-	-
Oil Well Pads	-	-
Water x-country lines	-	-
Water Well Pads	-	-
Gas x-country GLT/MI	-	-
Gas Well Pads	-	-
Gas - Yard Piping	-	2

ACT Table C.2 Endicott Leak/Save and Mechanical Repair Data

At Endicott there were two repairs for external corrosion on yard piping. There were no leaks.

Service	Leaks	Saves
Oil x-country	-	-
Oil Well Pads	-	-
Water x-country	-	2
Water Well Pads	-	-
Gas x-country	-	-
Gas Well Pads	-	-

ACT Table C.3 Milne Point Leak/Save and Mechanical Repair Data

At Milne Point there were two repairs on produced water flow lines; one due to external corrosion and the other due to mechanical damage. There were no leaks.

Service	Leaks	Saves
Oil – Well Pad	-	-
Gas – Well Pad	-	-
Disposal Well	-	-

ACT Table C.4 Northstar Leak/Save and Mechanical Repair Data

There were no leaks or saves for Northstar in 2009.

Service	Leaks	Saves
Oil – Well Pad	-	-
Gas – Well Pad	-	-
Disposal Well	-	-

ACT Table C.5 Badami Leak/Save and Mechanical Repair Data

There were no leaks or saves for Badami in 2009.

ACT Section D

Corrosion Monitoring and Inspection Goals

Section D ACT Corrosion Monitoring and Inspection Goals

Section D.1 2009 Corrosion Monitoring and Inspection Goals Reviewed

Section D.1.1 Corrosion Monitoring Summary

Weight loss coupons continued to be used for corrosion monitoring at Endicott, Milne Point and Northstar, as planned. A total of 50 coupons were exposed in flow lines and a total of 681 coupons were exposed in well lines. The weight loss coupon installation and removal frequency remained essentially unchanged in 2009.

The ER probe program consists of eleven active monitoring locations. The ER probe data is routinely incorporated into the corrosion control program.

The well line erosion rate monitoring program at Endicott continued as planned, with an improvement in velocity control demonstrated for individual wells and the overall average, as compared with previous years.

Section D.1.2 Mitigation Summary

Corrosion inhibitor applications for Milne Point produced water and 3-phase, Endicott produced water and Northstar 3-phase all met the target concentration levels for the year.

At Milne Point, 100% of the maintenance pig runs in the produced water lines were completed on-schedule and 96% of the maintenance pig runs in 3-phase lines were completed on schedule. Maintenance pigging of the Endicott IIWL is scheduled on a five-week interval and 100% of the maintenance pig runs were completed on-schedule.

At Northstar, relocation of the oxygen scavenger injection location to downstream of the point of oxygen ingress has demonstrated improved corrosion control in the produced water disposal system.

Section D.1.3 Inspection Summary

The fundamental elements of the Inspection Programs outlined in Appendix 3.3.3 (CRM, ERM, FIP, CIP and CUI) form the foundation for the inspection program for ACT.

In 2009 there were 4,738 external inspections and 10,389 internal inspections performed on ACT well lines and flow lines. Additionally 3,342 TRT external inspections were performed at Milne Point. Less than 1% of the external inspections at Milne were found with CUI.

For Endicott, Milne Point, Northstar and Badami combined, an average of 11,943 external and internal inspections have been performed per year over the last five years. The total number of inspections in 2009 was 15,127 which is considerably above the average level of activity. Inspection activity for 2009 was executed as planned and continues to be focused on the long term monitoring of key assets. Results of the inspection programs are monitored routinely and exceptions or increases are addressed as they arise during the year. A list of corrective actions resulting from flow line inspection increases is presented in the following section.

Section D.1.4 Corrective Actions

This section summarizes the corrective actions taken on cross-country flow lines as a result of corrosion monitoring and inspection results exceeding the specified targets.

One corrective action was performed on flow line NST 1024 as a result of ER probe monitoring results exceeding target corrosion rates and a weight loss coupon exceeding the target general corrosion rate of 2 mpy. One corrective action was performed as a result of inspection increases on a flow line. Results of the actions are shown in ACT Table D.1.

Equipment ID	No. of Action	Cause	Action
Inter-Island Water Line	1 Inspection Increase	Increased Corrosivity	Make adjustment to maintenance pig sizing and frequency
NST 1024	WLC >2 mpy	Increased Corrosivity	CI Increase
NST 1024	1 ER Probe excursion	Increased Corrosivity	CI Increase

ACT Table D.1 Corrective Mitigation Actions from Inspection and ER Probe Data

Section D.2 2010 Corrosion Management Goals

Section D.2.1 Endicott

The IIWL corrosion inhibition, maintenance pigging and monitoring program will continue, in order to maintain the current decreased trends in corrosion activity.

A new inhibitor is being considered in the Endicott water injection system given the successful results of the trial at Milne Point Unit.

The well line erosion rate monitoring program will continue in 2010; with the target being no individual well exceeding V/V_e >2.5 during any given month.

Carbon steel C-Spools will continue to be replaced on an as-needed basis with duplex stainless steel.

No significant changes to the corrosion monitoring program are anticipated.

Section D.2.2 Milne Point

The 2010 plan will continue the inspection program to provide feedback for corrosion control and mechanical integrity.

Section D.2.3 Northstar

Corrosion monitoring and inspection data will continue to be reviewed as the information becomes available. Changes to the inspection and mitigation activity will be dictated by these data in conjunction with process data. This is an ongoing activity that will continue for a number of years as the corrosion management evolves.

All new wells will be equipped with capability to inject corrosion inhibitor at the wellhead.

The gas injection system will continue to be monitored through inspection.

Section D.2.4 Badami

While on warm shut down, Badami will continue to be evaluated through the integrity plan to ensure that the plant is maintained properly.

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Appendix 1

Glossary of Terms

Glossary of Terms

Term	Definition/Explanation
3 phase production	Unprocessed well head fluids, oil, water, gas – same as OIL
ACT	Alaska Consolidated Team
ASCCP	Asset Specific Corrosion Control Plan
ATRT	Automated tangential radiographic testing
BAD	Badami
bpd	Barrels per day
BPXA	BP Exploration (Alaska) Inc.
CCL	Cross country line
CI	Corrosion inhibitor
CIC	Corrosion, Inspection and Chemicals
CIP	Comprehensive Inspection Program
CL	Common line – same as LDF
CMS	Corrosion management system
CPF	Central processing facility
CR	Corrosion rate, mpy
CRA	Corrosion resistant alloy
CRM	Corrosion rate monitoring inspection program
Cross Country lines	Pipelines from the manifold building to major facility
CUI	Corrosion under insulation
CW	Commingled Water
DRT	Digital radiography
END	Endicott
ER	Electrical resistance probe – see corrosion monitoring
ERM	Erosion rate monitoring inspection program
FL	Flow line – same as cross-country
FIP	Frequent inspection program
Frequency C	Continuous
Frequency D	Daily
Frequency H	Hourly
Frequency M	Monthly
Frequency Q	Quarterly
Frequency Y	Yearly/annual
FS	Flow station
G	Gas
GC	Gathering center
GIS	Geographical Information System
GLT	Gas lift transit
GPB	Greater Prudhoe Bay
IIWL	Inter Island Water Line - Endicott
ILI	In-line Inspection or Smart Pig
LDF	Large diameter flow line – same as CL
LIS	Lisburne
LRGWUT	Long Range Guided Wave Ultrasonic Testing
MAOP	Maximum Allowable Operating Pressure
MFL	Magnetic flux leakage
MI	Miscible injectant
mil	0.001 in.
MIMIR	**M**echanical **I**ntegrity **M**anagement **I**nformation **R**epository BPXA corrosion and inspection database

Glossary of Terms

Term	Definition/Explanation
MPI	Main Production Island - Endicott
Mbpd	Thousands of barrels per day
mpy	Corrosion rate/degradation rate – mils per year
MPU	Milne Point Unit
MW	Mixed water
NDE/NDT	Non-destructive examination/testing
NIA	Niakuk
NGL	Natural gas liquids
NST	Northstar
OIL	OIL service is 3-phase production service
OWG	Oil, water and gas – 3-phase production
PBU	Prudhoe Bay Unit
PO	Processed oil
ppb	Parts per billion
ppm	Parts per million
PR	Pitting rate, mpy
PTMAC	Point McIntyre
PW	Produced water
RT	Radiographic testing
SDI	Satellite drilling island
Sleeve	Mechanical repair
Slug catcher	First stage pressure vessel of OWG separation facility
STP	Seawater Treatment Plant
SW	Seawater
TR	Transit line
TRT	Tangential radiographic testing
UT	Ultrasonic testing
VSM	Vertical support member
WAG	Water alternating gas
WL/Well lines	Pipelines from the well head to manifold building
WLC	Weight loss coupon
WPM	Well pad manifold building
WSS	Walking speed survey
WTR	Combined seawater and produced water injection
X-country	Cross country

Appendix 2

Charter Agreement – Corrosion Related Commitments
Work Plan
Guide for Performance Metric Reporting

Charter Agreement – Corrosion Related Commitments

The BPXA contact for all corrosion matters relating to the Charter Agreement is,

Bill Hedges, Corrosion Strategy and Planning Manager

E-mail:bill.hedges@bp.com

Phone: (907) 564-4466

Project Achievements

Oct-Nov 2000	Work Plan agreed between BPXA/PAI and ADEC (Appendix 2a)
March 2001	1st Annual Report submitted to ADEC
April 2001	1st 2001 Meet and Confer session held
Oct-Dec 2001	Consultations with ADEC and ADEC's consultant
November 2001	2nd 2001 Meet and Confer session held
Dec 01-Jan 02	Developed and agreed corrosion management metrics
February 2002	BPXA/PAI and ADEC agreed on performance metrics (Appendix 2b)
March 2002	2nd Annual Report submitted to ADEC
April 2002	1st 2002 Meet and Confer session held
November 2002	2nd 2002 Meet and Confer session held
March 2003	3rd Annual Report submitted to ADEC
May 2003	1st 2003 Meet and Confer session held
October 2003	2nd 2003 Meet and Confer session held
March 2004	4th Annual Report submitted to ADEC
April 2004	1st 2004 Meet and Confer session held
August 2004	North Slope Field Trip
March 2005	5th Annual Report submitted to ADEC
May 2005	1st 2005 Meet and Confer session held
August 2005	North Slope Field Trip
March 2006	6th Annual Report submitted to ADEC
May 2006	1st 2006 Meet and Confer session held

November 2006	2^{nd} 2006 Meet and Confer session held
March 2007	7^{th} Annual Report submitted to ADEC
April 2007	1^{st} 2007 Meet and Confer session held
November 2007	2^{nd} 2007 Meet and Confer session held
March 2008	8^{th} Annual Report submitted to ADEC
May 2008	1^{st} 2008 Meet and Confer session held
October 2008	2^{nd} 2008 Meet and Confer session held
March 2009	9^{th} Annual Report submitted to ADEC
April 2009	1^{st} 2009 Meet and Confer session held
October 2009	2^{nd} 2009 Meet and Confer session held
March 2010	10^{th} Annual Report submitted to ADEC

Annual Charter Timetable

March 31^{st}	Annual Report submitted
April 30^{th}	1^{st} Semi-Annual Review/Meet and Confer
October 31^{st}	2^{nd} Semi-Annual Review/Meet and Confer

2000 Work Plan

Commitment to Corrosion Monitoring

Phillips Alaska, Inc.
BP Exploration (Alaska) Inc.

“BP and Phillips will, in consultation with ADEC, develop a performance management program for the regular review of BP's and Phillips’ corrosion monitoring and related practices for non-common carrier North Slope pipelines operated by BP or Phillips. This program will include meet and confer working sessions between BP, Phillips and ADEC, scheduled on average twice per year, reports by BP and Phillips of their current and projected monitoring, maintenance and inspection practices to assess and to remedy potential or actual corrosion and other structural concerns related to these lines, and ongoing consultation with ADEC regarding environmental control technologies and management practices.”

Work Plan Purpose:

The purpose of this work plan is to clearly define the purpose, scope, content, reporting requirements, roles and responsibilities, and milestones/timing for the development and implementation of the Corrosion Monitoring Performance Management Program required by Paragraph II.A.6 of the North Slope Charter Agreement.

Corrosion Monitoring Performance Management Program

Purpose: To provide for 'the regular review of BP and PAI’s corrosion monitoring and related practices for non-common carrier North Slope pipelines' operated by BP or PAI.
'Corrosion Monitoring' specifically refers to the activity of monitoring pipeline corrosion rates via corrosion probes, corrosion coupons, internal pipeline inspections, and external pipeline inspections.
'Related practices' refers to the assessment of corrosion monitoring data and the associated response to the assessment, specifically chemicals, inspection, and repairs.

Scope: Non-common carrier North Slope pipelines operated by BP or Phillips Alaska, Inc.

"Non-common carrier pipelines" refer to Non-DOT-regulated pipelines. Included in this designation are cross-country and on-pad pipelines in crude, gas, and other hydrocarbon services, as well as, produced water and seawater service pipelines. In module and inter-module on pad piping are not considered part of the scope of this review program.

Content: This Corrosion Monitoring Performance Management Program consists of the following:

1. BP and PAI will "meet and confer" with ADEC twice per year, on average. These sessions will be "working sessions" where BP and PAI will inform ADEC of the following:
   A. Summary description of the inspection and maintenance practices used to assess and to remedy potential or actual corrosion, or other significant structural concerns relating to these lines, which have arisen from actual operating experience. This description will address overall areas of focus, the rationale for this focus, and the nature of monitoring and related practices used during the time since the last meeting. This description may be brief if strategies/focus areas have not changed since the last meeting.
   B. Summary overview of ongoing coupon and probe monitoring results.
   C. Summary overview of chemical optimization activities.
   D. Summary overview of ongoing internal inspection activities.
   E. Summary overview of ongoing external inspection activities.
   F. Summary overview of ongoing structural concerns.
   G. Summary of conclusions drawn and responses taken to remedy potential or actual corrosion concerns relating to these lines.
   H. Review/discussion of corrosion or structural related spills and incidents
   I. Review the actions developed by the operator to address any corrosion performance trends that significantly exceed expected parameters.
   J. Summary of program improvements and enhancements, if applicable.
   K. Review of annual monitoring report (see below) at the next scheduled semi-annual meeting.

The agenda for these meetings will also include an opportunity for open discussion and an opportunity for ADEC to ask questions, provide feedback, etc.

These meetings will be targeted for April and October of each year, although this timing can be adjusted upon the mutual agreement of BP, PAI, and ADEC. The location of the meetings will alternate between the parties.

2. BP and PAI will submit annual reports to ADEC, which will provide the status of current and projected monitoring activities. These reports will be issued on or before March 31st of each year, and reflect the prior calendar year. The following information will be provided:

   A. Annual bullet item reporting the progress of the Charter Agreement corrosion related commitment.

   B. A general overview of the previous year's monitoring activities.

   C. Metrics that depict coupon and probe corrosion rates.

   D. Metrics that characterize chemical optimization activities.

   E. Metrics that depict the number and type of internal/external inspections done, and, as applicable, the corrosion increases/rates and corresponding inspection intervals.

   F. Metrics that characterize the quantity and type of repairs made in response to the internal/external inspections done per the above paragraph.

   G. Metrics that depict the numbers and types of corrosion and structural related spills and incidents.

   H. A forecast of the next year's monitoring activities in terms of focus areas and inspection goals. These forecasts cannot be viewed as binding, as corrosion strategies are dynamic and priorities will change over the course of the year. However, changes in focus will be communicated to ADEC during the semi-annual meetings described above.

   Note: These reports will be presented in, and be part of, a comprehensive North Slope Charter Agreement status report.

3. In addition to the semi-annual "meet and confer" working sessions referenced above, BP and PAI will remain accessible to provide "ongoing consultation" to ADEC regarding environmental control technologies and management practices.

   'Environmental Control Technologies' refer to those technologies specifically related to corrosion monitoring and mitigation of the subject pipelines.

   'Management practices' refer to corrosion monitoring and related practices as defined above.

4. During the semi-annual 'Meet and Confer' working meetings with BP and/or PAI, ADEC may use the services of a corrosion expert(s) (contracted from

funds under Charter Commitment paragraph II.A.7) to assist in the review of performance trends and corrosion program features.

5. BP has assigned CIC Manager, R. Woollam/564-4437, and Phillips has assigned Kuparuk Engineering and Corrosion Supervisor M. Cherry and J. Huber/659-7384, to be the contacts responsible for ensuring these commitments are met, including ADEC notification of scheduled times for the semiannual presentations. The ADEC contact for this effort is (Pipeline Integrity Section Manager/S. Colberg/269-3078) who will notify interested personnel of the presentation times, maintain the reports for distribution to the public when requested and coordinate other issues relating to this commitment.

Annual Timetable

March 31st	Annual Report
April 30th	1H Semi-Annual Review (Meet and Confer)
October 31st	2H Semi-Annual Review (Meet and Confer)

Guide for Performance Metric Reporting

General

- Different metrics show and reveal different aspects of the business and as a consequence there are rarely any 'right' or 'wrong' measures only 'right' or 'wrong' application and usage.
- Summary statistics described below may be provided as a data appendix to the annual reports with the more pertinent tables and graphics being contained in the text as appropriate. The intent is not to clutter and interrupt the flow of the text with extraneous data.
- Format of data, the order in which it is presented, etc. of each company's annual report may differ from the order presented below, depending on key messages and data context. For example, one company may choose to imbed Leak/Save data into an inspection graph as opposed to presenting the Leak/Save data in standalone tabular format.
- This is an initial document for implementation in the 2001 annual report to ADEC, it should be noted, that the guidelines provided below can and will be adjusted to improve the efficacy of the annual report and reporting mechanism.

Timescale

- Data to be presented on an aggregate annualized basis.
- Base year 1995 providing 5 year history before the start of the Charter Agreement and each year's annual report will add to time series starting in 1995.
-

Equipment Classification

- **Well Line** Pipe work from the well head to the Well Pad Manifold Building, generally, the flow from a single well prior to commingling before transportation to the separation plant.
- **Flow Line** Pipe work from the Well Pad Manifold Building to the Separation plant, generally, cross country and off pad pipe work which carries commingled flow to/from a well pad. Also, straight run flow from the wellhead to separation plant, without commingling, is classified at Flow Line pipe work.
- **Exceptions** Pipe work not conforming to these basic definitions will be reported by exception.

Service Definitions

- **3-phase Production (3ø or OWG)** Basic reservoir fluids (O/W/G – oil, water and gas) produced from down hole through to the main separation plants that typically see only see changes in temperature and pressure from reservoir conditions and are therefore essentially un-separated.
- S**eawater (SW)** Water sourced typically from the Beaufort Sea that has undergone primary treatment at the Seawater Treatment Plant. Note, that the seawater treatment plants differ across the slope in the primary treatment methods, most importantly oxygen removal, with both production gas and vacuum stripping being employed.
- **Produced Water (PW)** The water produced with the primary reservoir 3 phase production after passing through the separation and treatment
- **Commingled Water (CW)** or Mixed Water (MW) Water which has been commingled and is therefore multi-sourced, this is typically a mix of SW and PW although other combinations exist in the operations on the North Slope.
- **Gas (G)** Generic term for a number of different gas systems which transport essentially dry gas between facilities including fuel gas, lift gas and miscible injectant.
- **Processed Oil (PO)** The oil/hydrocarbon produced with the primary reservoir 3 phase production after separation and treatment; this is primarily black oil but could include black oil plus NGL's.

Basic Summary Statistics

- **Distribution** The data is fundamentally of log-normal distribution, with a lower limit of zero or no-change and potentially unlimited upper extent.
- **Count** A count of the number of activities completed i.e. coupons pulled in a given year.
- **Average** The average or mean for the criteria being summarized i.e. average corrosion rate.
- **Target Value** The target value against which non-conformance, see below, is reported.
- **Number Non-conformant** The number of items not conforming to the control criteria i.e. the number of coupons exceeding the control value.
- **Percentage Non-conformance** The percentage not conforming to the control value as a percentage of the total.

Weight Loss Coupon Data

Table below summarizes the reporting of weight loss coupon data for the major fields on the North Slope

	Well Lines	CCL/FL
3 ø Production	All	All
Seawater	GPB	All
Prod. Water	GPB	GPB
Commingled Water	All	All

The data sets to be provided for both general corrosion rates and pitting rates are,

- Count of coupons,
- Average corrosion rate,
- Number non-conformant,
- % Conformant i.e. 1 minus the % non-conformant.

A corrective action list for non-conformant flow lines (FL/LDF/CCL/CLs) will also be provided.

Internal Inspection Data

Table below summarizes the reporting of internal corrosion inspection data for the major fields on the North Slope:

	Well Lines	CCL/FL
3 ø Production	All	All
Commingled Water	All	All

Note that no distinction will be made between water services across the North Slope since in many cases the service is variable making meaningful analysis and aggregation difficult.

The data sets to be provided for internal inspection are,

- Count of inspections,
- Number of increases on repeat inspection locations,
- Percentage of increases on repeat inspections.

A corrective action list for flow lines (FL/LDF/CCL/CLs) with inspection increases will also be provided.

Corrosion Inhibition

The corrosion inhibition program is to be reported as the target and actual total annual gallons and gallons per day, and as concentration, ppm, based on a field wide average.

External Corrosion Inspection

External corrosion inspection program is to be reported as an aggregate of all piping systems without distinction or differentiation of service and equipment type with a summary of the overall program status.

The data sets to be provided for external inspection are,

- Count of inspected location,
- Number of corroded locations,
- Percentage of inspection locations corroded.

Repair and Leak Statistics

The repair and leak/spill statistics to be reported for each year plus the historical trend back to 1995 consistent with other performance metrics. The basic definitions,

Leak/Spill An agency reportable leak/spill for the pipelines covered under the Charter Agreement which was caused by corrosion and/or erosion

Save A location which required repair action as a result of corrosion and/or erosion damage but which was found through inspection prior to causing a leak/spill

The data sets to be provided for Repair/Leak statistics,

- Count of Leaks/Saves by flow line and well lines,
- Summary of leak/spill causes.

Below Grade Piping

The data sets to be provided for Below Grade Piping (BGP) program,

- Number of segments/crossings inspected broken out by inspection method,
- Number with anomalies and severity of anomaly.

Results of casing digs, visual casing inspections and casing clean-out to be reported as appropriate.

Other Programs

Reporting of ER probe, smart pigging, maintenance pigging, structural issues, and details of individual spill incidents will be reported as dictated by the current year's program activity.

Appendix 3

Corrosion Management System

Appendix 3. Corrosion Management System

This section summarizes the Corrosion Management System (CMS) in use at the Greater Prudhoe Bay (GPB) and Alaska Consolidated Team (ACT) Performance Units. Figure 7 contains a schematic of a typical production facility configuration. A map and brief description of each field and the associated production facilities can be found in Figure 8 and Table 16 BPXA North Slope Operations.

Appendix 3.1 Corrosion Management System

Appendix 3.1.1 Description

The Corrosion Management System consists of a number of major program elements: Corrosion Monitoring, Erosion Monitoring, Corrosion Mitigation, Inspection and Fitness-For-Service assessment, which follow a simple management process, represented in Figure 1. The CMS elements are summarized in Table 9, Table 10 and Table 11, at the end of this section. The Corrosion, Inspection and Chemical (CIC) Group utilizes data presented in this report as part of the overall Corrosion Management System.

A successful corrosion management program is influenced by a number of processes and procedures including:

- Identification of corrosion threat and determination of susceptibility;
- Corrosion monitoring to assess corrosivity, potential changes within a system, and to determine mitigation activity;
- Corrosion mitigation as a means of imparting a level of control over a particular system. This can include both corrosion management and operational changes;
- Inspection procedures and practices to develop the required understanding of both damage assessment and level of control;
- Operational requirements that can affect the level of integrity within a system, including well work, production characteristics, and operation of specific equipment; and
- The effect of changes both short- and long-term (creeping change) that can significantly alter the life cycle of the equipment.

The overall objective of the CMS is to meet the corporate objectives of 'no accidents, no harm to people and no damage to the environment' which translates for corrosion management within BPXA to delivering a mechanical integrity program which:

- Minimizes health, safety, and environmental impacts of corrosion resulting from a loss of containment.
- Provides an infrastructure fit-for-service for the remainder of the life of the oilfield.
- Provides infrastructure of sufficient mechanical integrity capable of producing satellite fields/accumulations through existing main production facilities and infrastructure.
- Provides an infrastructure to support future major gas production and sales through current North Slope facilities.

These overall goals and objectives are achieved through a comprehensive Corrosion Management System that consists of an integrated system of strategy, processes and programs.

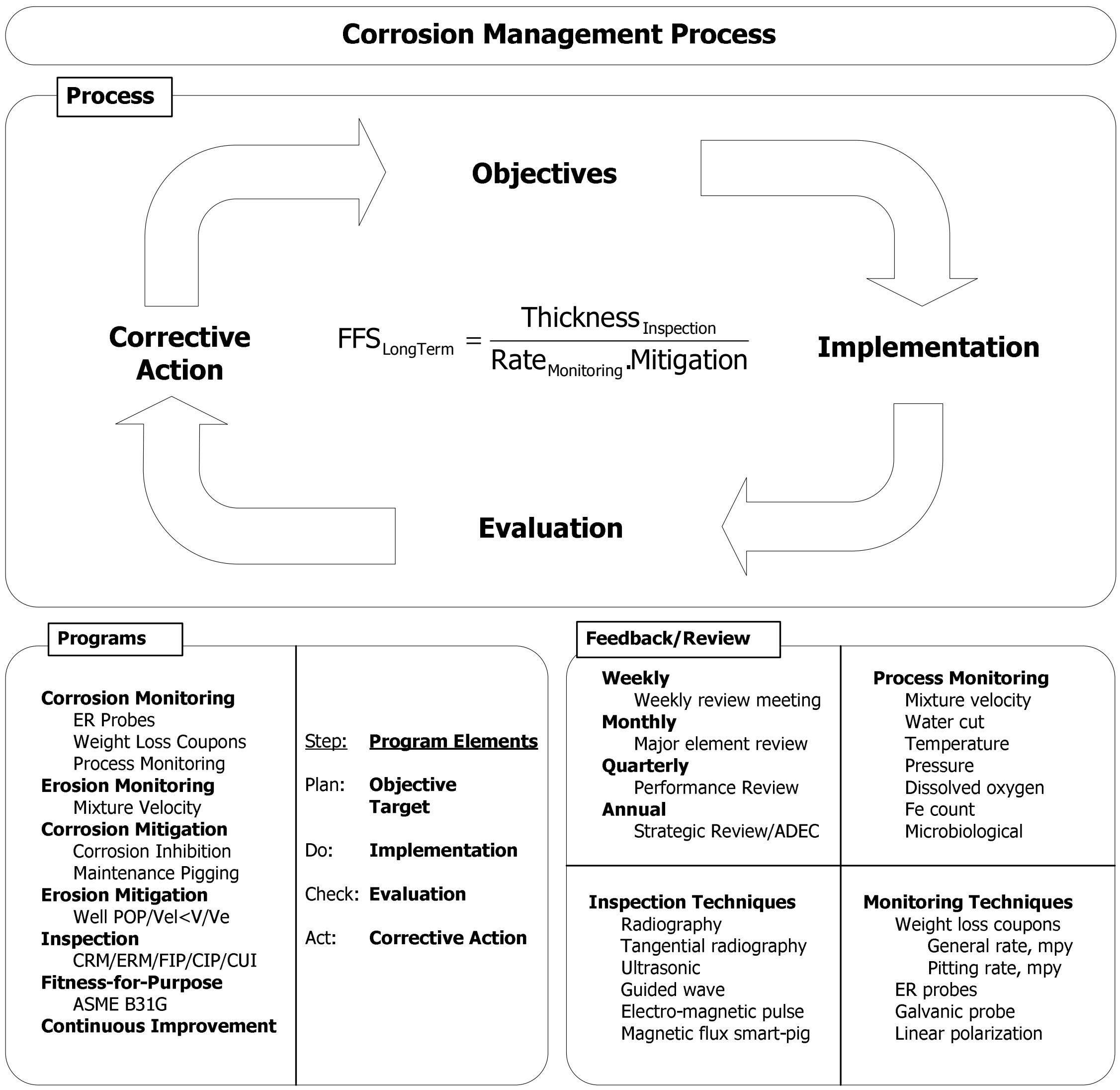


Figure 1 Overview of the Corrosion Management Process

Appendix 3.1.2 Process

Within the overall Corrosion Management System, each specific program element, i.e. Corrosion Monitoring, Mitigation, Inspection and Fitness-For-Service, follows the classic TQM (Total Quality Management) process of 'plan-do-check-act' as shown in Table 1.

Step	Activity	Description
Plan	Objective	The program objective and purpose
	Target	The metric against which performance is assessed
Do	Implementation	Implementation plan to achieve objective
Check	Evaluation	Method to evaluate performance of plan against target
Act	Corrective Action	The action required to correct deviation from target

Table 1 Corrosion Management Process

Appendix 3.1.3 Objectives and Targets

The objectives[11] for the CMS are set in order to support the delivery of the corporate objective and BPXA objectives described in Part 1 – Overview. For the purposes of the CMS these can be translated into the corrosion management objectives of;

- Eliminate corrosion and erosion related failures,
- Provide Fit-For-Service infrastructure to the end of field life.

Based on these objectives, individual targets are set for the corrosion, erosion, mitigation and inspection programs, which in combination are designed to deliver the objectives. The overall business objectives and individual program objectives and targets are described in detail in Table 9, Table 10 and Table 11.

For example, the weight loss coupons (WLC) in the 3-phase production system have a corrosion rate target of 2 mils per year (mpy). The monitoring program objective is to meet or beat this target, which means an actual WLC corrosion rate of 2 mpy or less (WLC 2 mpy).

Appendix 3.1.4 Implementation

There are a number of different corrosion monitoring and inspection techniques, each of which has both advantages and disadvantages. The advantages and disadvantages, or strengths and weaknesses, make the results from an individual technique more or less applicable depending on the application circumstances.

Table 12, Table 13, and Table 14 summarize the main categories of corrosion monitoring, process monitoring, inspection techniques and briefly summarize relative strengths and weaknesses for different applications.

Appendix 3.1.5 Evaluation

The elements of the CMS must be considered relative to the unique characteristics of each operating system to reflect their applicability and efficacy. The corrosion and erosion monitoring, inspection and mitigation practices for the major services and equipment type are summarized in Table 15.

[11] In addition to Charter Work Plan, some information is supplied to provide additional context and help in understanding BPXA corrosion management activities

The results from each of the corrosion management programs are reviewed on a regular basis to provide feedback and to take any necessary corrective action based on deviation from target performance. In general, the major review cycles within the CMS are presented in Table 2.

Review	Description
Weekly	A weekly internal review meeting at which the latest corrosion monitoring, mitigation, inspection and process data is analyzed and reviewed, and any tactical changes implemented
Monthly	Monthly summary of the major elements of the program are reviewed for the need for longer term corrective action
Quarterly	Quarterly strategic performance review held in order to ensure that the implementation plan is delivering the strategic objectives
Annual	Annual program and strategy review designed to review the strategic direction of the program and review effectiveness of the current programs in delivering the strategic direction, e.g. Annual Report to ADEC

Table 2 Corrosion Management Feedback Cycles

Based on the results of the evaluation process, corrective action plans are developed and the overall management program and strategic direction are reviewed.

Appendix 3.1.6 Corrective Action

Corrective actions provide feedback to the adjustment and setting of Objectives and Targets. Corrective actions can be broken down into five basic categories;

- Chemical Mitigation,
- Operational Intervention,
- Reduce Maximum Operating Pressure (Derate),
- Repair/Replacement,
- Abandon or Remove from Service.

Chemical mitigation is discussed in detail in Section A. Operational intervention centers on the BPXA Velocity Management Program that is designed to control internal mixture velocity below target values dependent on equipment type, water cut and line size. Repair/replacement programs are driven by the inspection findings and include mechanical sleeves, pipe work refurbishment, and pipeline replacement.

Appendix 3.2 Corrosion and Inspection Data Management

In order to deliver a comprehensive corrosion management program and manage the extensive corrosion monitoring and inspection activity, it is necessary to have an active and structured electronic database.

With the introduction of single-operatorship at Greater Prudhoe Bay one of the major problems faced by the CIC Group was the integration of two historical data sets for inspection, corrosion monitoring and corrosion mitigation information.

Through significant effort, two different histories from incompatible databases based on early 1990's technology were merged into one functional database.

Appendix 3.2.1 Mechanical Integrity Management Information Repository (MIMIR) Database

To deliver a comprehensive corrosion management program, it is necessary to have an active and structured electronic database. MIMIR is a corrosion information management system used to control, record, and audit corrosion-related data.

The database development effort has involved a dedicated team of software developers and resources from within the CIC-CSP Group. Updates and improvements to MIMIR are made on a regular basis; continually increasing the functionality and integrity of the database.

Users of the system are provided two primary methods for accessing information stored in the database. The first is a custom user interface written in Microsoft Visual Basic©, and the second is through ad-hoc data query tools such as BrioQuery© and BusinessObjects© which allow free-form SQL© access to the data.

Checks for data integrity are provided at a number of different levels including error checking at the point of data capture and data entry, regular reviews of data quality, and data entry rules within the database.

The data is continuously monitored for integrity, quality and consistency; as a consequence any errors detected are corrected as they are found. In addition, as better analysis capabilities become available through further data integration, records may be amended to reflect the improved level of understanding.

MIMIR is a 'live' database. As a result of ongoing quality efforts and the tracking of production/service conditions, changes in the physical system are reflected in the database records. The following are some of the reasons that values returned from MIMIR change through time,

Quality Control and Audit A fundamental design philosophy for the database was that errors should be corrected through time as they are discovered. Therefore as the database is used and the quality control rules and procedures applied, data-entry, translation and record-keeping errors are eliminated.

Equipment Service Changes The database tracks active, in or out-of-use equipment, and equipment service changes. As a piece of equipment moves through different services and different status, then the data in the database tracks the equipment status.

Transition Issues As noted above, the two historical databases, heritage East and heritage West, were incompatible with very different structures and data fields.

Therefore these have had to be translated to the new system. As the quality control and audit tools are applied to the translated data, error and mistranslations are removed.

Time The database is in active use with data being added everyday, given that there is sometimes a time delay between the reporting date and entry date then the data totals can and do change.

Table 3 gives an illustration of the number of records and the rate at which those records are accumulated on an annual basis in the database. The table clearly shows the level of complexity and volume of data involved in managing the corrosion programs.

In addition, the table also shows that the range and type of information being gathered is being improved through time to enable better overall corrosion management. The most notable examples of this increasing range of coverage of the corrosion and inspection database is the inclusion of the production and injection data, the introduction of chemical usage data and the long term storage of ER probe data.

Data Record	Unit	Records	#/year	History
Weight loss coupons	10^6	0.26	0.01	31 years
ER probes readings	10^6	2.33	0.21	8 years
Equipment	10^6	28.2	-	32 years
Inspection locations	10^6	0.78	0.09	32 years
Inspection records	10^6	2.05	0.17	32 years
Chemical injection	10^6	58.7	14.7	4 years
Production rates	10^6	7.01	0.29	25 years
Injection rates	10^6	3.21	0.21	26 years

Table 3 Database Record Accumulation Rate (as of Dec-2009)

Appendix 3.2.2 Historical Data

The small differences in data between Annual Reports reflect the movement of lines into and out of service, the addition or abandonment of equipment, and the addition or removal of corrosion access fittings to the program. The historical data for prior years has been updated to reflect the current equipment inventory.

Appendix 3.3 Corrosion Management Context

The following sections are provided to lend context to the current year results.

Appendix 3.3.1 ER Probe and Corrosion Inhibitor Response

This section describes, by example, the methodology by which corrosion inhibitor concentration is increased as a result of corrosion monitoring through the use of ER probes on large diameter 3-phase production flow lines.

Figure 2 and Table 4 illustrate the use of ER probes in managing changing corrosion conditions in a large diameter flow lines. Figure 2 shows the ER probe readings and derived corrosion rates, over a period of approximately 10 months in 2003. For the first 10 weeks the measured corrosion rate is bordering on 2 mpy and a 5% increase in CI is implemented. In early February the existing ER probe was replaced due to data quality issues. In mid March another increase of CI was implemented based on ER probe corrosion rate. During April and part of May, the CR still exceeded the target and two additional CI increases were implemented. Finally in mid-May, the CR falls below the 2 mpy target and the CI remains at the increased concentration.

Time Period	**Comments**
14-Jan	Probe placed on watch list
14-Jan to Feb 11	Probe at or near 2 mpy, 5% increase in pad CI target
14-Feb	Poor data quality, ER probe replaced.
18-Feb to 21-Mar	Probe continues to show rate >2mpy, 10% increase in pad CI target
21-Mar to 30 Apr	Probe continues to show rate >2mpy, 10% increase in pad CI target
01-May to 01-Oct	Probe shows rate <2mpy, No adjustments to CI target

Table 4 Corrosion Inhibitor Concentration vs. Corrosion Rate

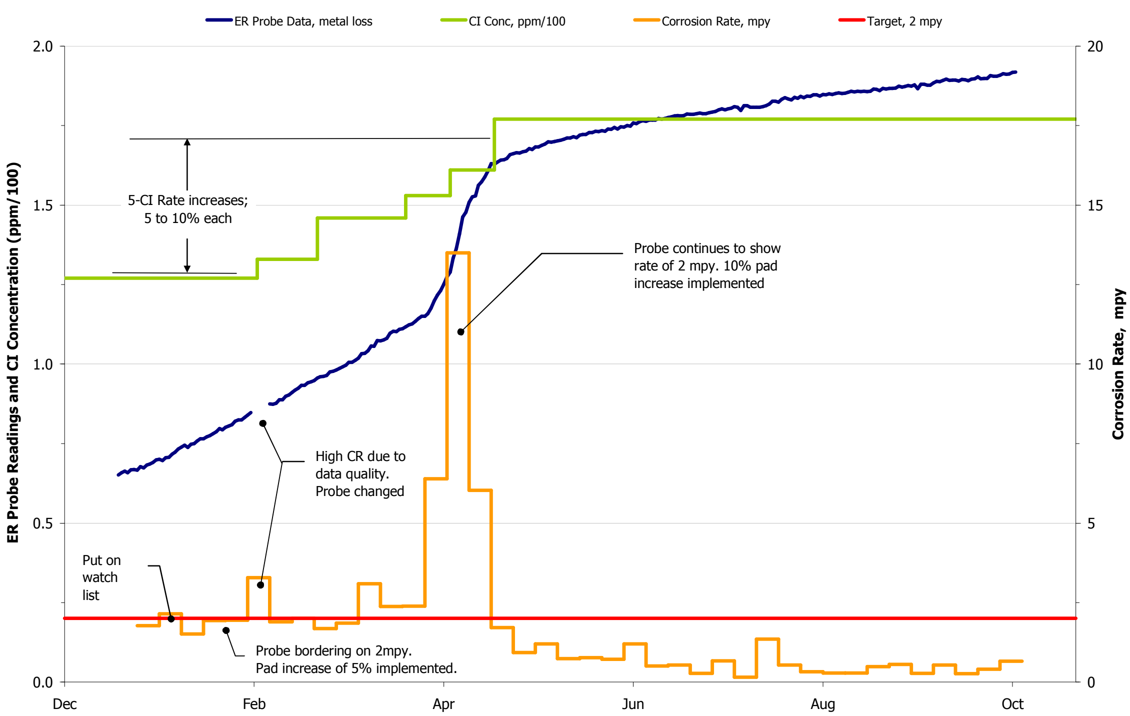


Figure 2 Corrosion Inhibitor Concentration vs. Corrosion Rate

Appendix 3.3.2 Corrosion Inhibitor Development

The development of new corrosion inhibitors starts in the research and development laboratories of the chemical suppliers where potential products are tested for effectiveness under a range of conditions designed to simulate production fluids. Once these preliminary test chemistries have passed the laboratory screening process, the promising products are tested under field conditions using dedicated test facilities at GPB. The test process is summarized in Table 5.

In 2003, a new standardized protocol for well line testing was developed. New products are first tested on a small scale test using an individual well line with each test lasting ~2 days and using approximately 5 gallons of the corrosion inhibitor under evaluation. Products that successfully pass the well line test program are then considered for a large-scale field trial.

The large-scale field trial involves converting between one and three well pads to the test product for 90 days and using 20-40,000 gallons of test chemical. This enables corrosion probe, coupon, and inspection data to be generated to verify the test product's effectiveness as a corrosion inhibitor. The large-scale field trial also allows assessment of the impact of the product on oil separation and stabilization process. Progress is being made in developing a new, standardized protocol for more rapid verification of a product's effectiveness as a corrosion inhibitor.

Location	Test	Description
Laboratory	Wheel-box Test	Performance of new potential corrosion inhibitor actives is compared to high performing actives. The test conditions simulate GPB and the test is run for 24 hours. Performance is determined by coupon weight loss.
	Kettle Test	This investigates the ability of an inhibitor formulation to partition from an oil phase into a brine phase under stagnant conditions. Test duration is 16 hours and corrosion rate is determined by linear polarization resistance (LPR) probes.
	HP Autoclave	This method determines the performance of inhibitors under high pressure and high temperature conditions. Monitoring method is by either coupon weight loss measurements or LPR. Test duration varies from 1 to 7 days.
	Jet Impingement	A once-through jet impingement configuration evaluates the performance of an inhibitor formulation under extremely high shear conditions. The persistency of the inhibitor film can also be determined. Test duration is one hour and corrosion rate is determined by LPR measurements.
	Flow Loop Test	The ultimate laboratory scale test that simulates temperature, pressure and flow conditions including velocity and water cut. Typical test duration is 24 hours and corrosion rate is determined by LPR measurements.

Location	Test	Description
Field	Well Line Test	Dedicated test well lines are used at GPB as the first step in the field-testing process. Typically 5 gals of chemical used with a test duration of 2 days.
	Large Scale Test	1 to 3 well pads using 20-40,000 gallons of corrosion inhibitor with a test duration of 90+ days. Allows the evaluation of corrosion inhibitor performance by ER, WLC, and inspection, as well as impact of product on separation plant performance.
	Evaluation	Products are evaluated against both technical performance and cost effectiveness criteria in order to assess if there is an overall improvement in performance.
GPB	Implementation	Once a decision has been made to convert the field to a new product, additional precautions are taken with additional corrosion monitoring and plant performance evaluations in order to assure product efficacy.

Table 5 Summary Description of the Available Test Program Components

As an example, the ER probe results from a typical cross-country flow line test are shown in Table 6 and are summarized in Figure 3. Based on these data, the test chemical in this example was not as effective at the same dosage rates as the incumbent and therefore was not utilized across the field.

Status	Chemical	Conc. ppm	CR, mpy	Notes/Comments
Baseline	Incumbent	130	0.2	
Stage 1	Test	150	8.1	Even at a higher dose rate the test chemical was unable to inhibit corrosion to the same level as the incumbent.
Stage 2	Test	170	2.0	Reduces corrosion rate.
Stage 3	Test	190	0.8	Dose rate was increased in order to achieve the same level of corrosion control as the incumbent. At this increased level of corrosion inhibition the test product was uneconomic and the test was terminated.
Return	Incumbent	130	0.1	Re-inject the incumbent product and corrosion rates return to the same level as those prior to the test.

Table 6 Flow line Test Program Result Summary

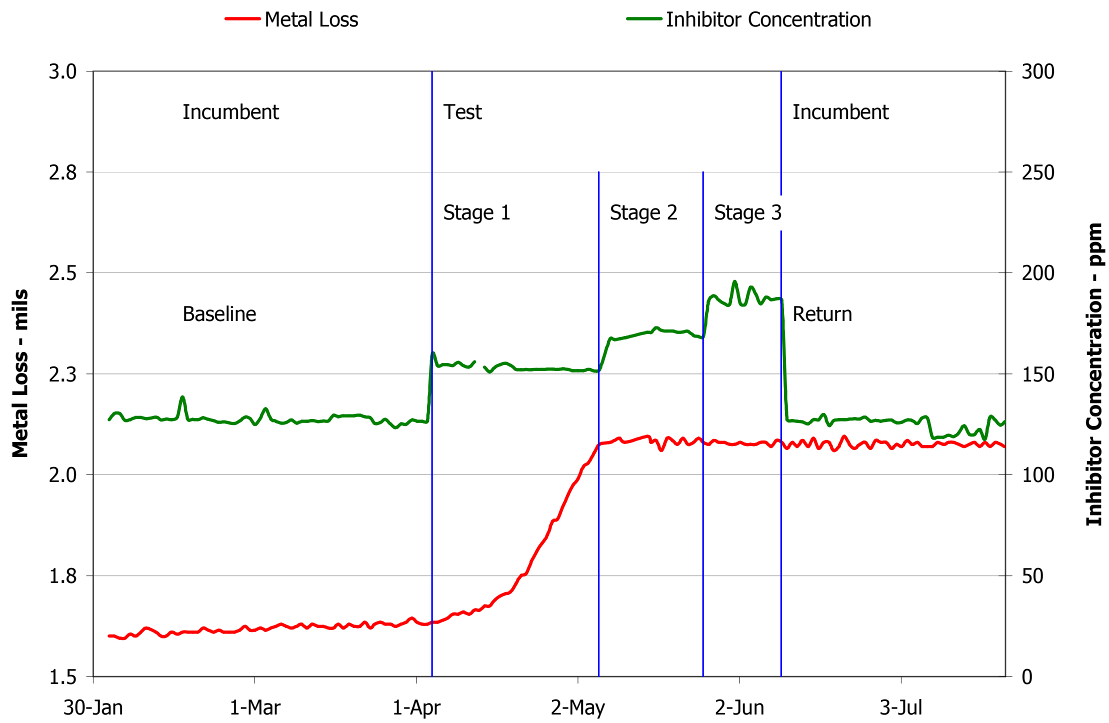


Figure 3 ER Probe Chemical Optimization Test

A second example, utilizes the output from the weight loss coupon program. This example from a test performed in 2001, demonstrates the need/value of multiple monitoring techniques when evaluating corrosion inhibitor performance. The trial product was tested for a 90-day period with no negative response observed by the ER probes. However, after the 90-day test period the corrosion coupons were pulled and showed relatively high general corrosion and pitting rates - see Figure 4. The product evaluated was a failure and the incumbent product was re-instated based on the coupon results. Corrosion inhibitor tests use all the monitoring tools available such as corrosion probes, coupons, and inspection data to determine corrosion control performance. In addition, the corrosion inhibitor is evaluated for plant production performance to show compatibility with the separation process.

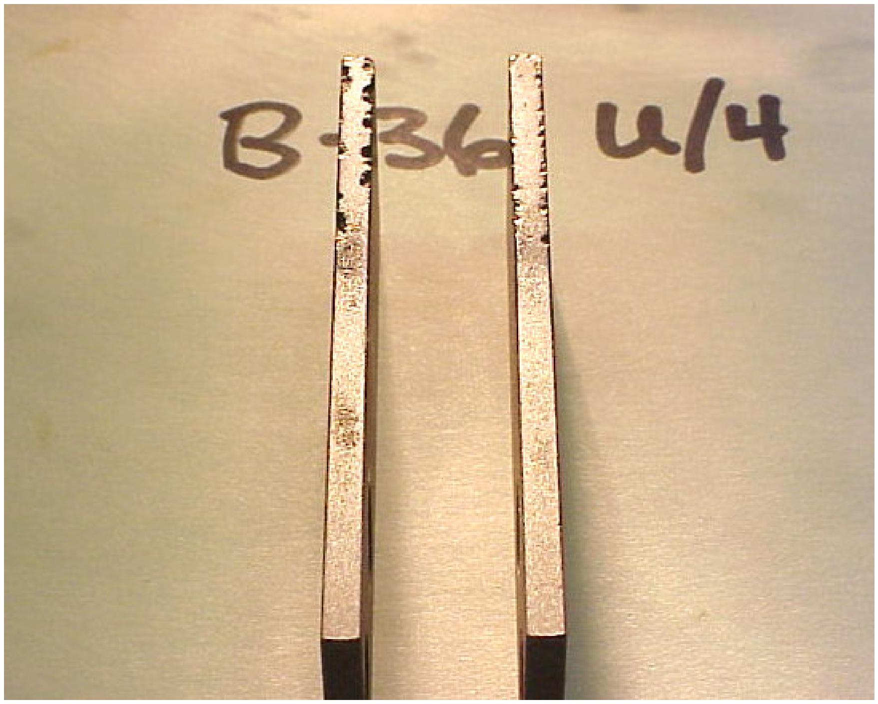


Figure 4 Corrosion coupons pulled after an 'unsuccessful' chemical trial

Appendix 3.3.3 Internal Inspection Program – Scope

This section summarizes the scope and criteria used to determine the frequency of inspection for the internal corrosion inspection program. The over-riding factor in determining inspection intervals is the purpose of inspection based on a combination of equipment condition, corrosion rate, and operating environment. The internal inspection program is sub-divided into four elements, each with a separate purpose and therefore frequency of inspection:

CRM – Corrosion Rate Monitoring: The goal of this program is to detect active corrosion in support of corrosion control activities, primarily the chemical inhibition program. The data is complimentary to other monitoring data, such as corrosion probes and corrosion coupons. As the primary aim is to determine when corrosion occurs, this program is of fixed scope at fixed inspection intervals. For a typical cross-country pipeline, the CRM program includes up to 40 inspection locations which include examples of all locations susceptible to corrosion, such as elbows, girth welds, long seam welds, bottom of lines sections, etc. These locations are each inspected twice per year. The inspections are staggered, with half the set being completed in the 1st calendar quarter and half in the 2nd. These are repeated in the 3rd and 4th quarters, respectively. Therefore, information regarding the level of active corrosion (or lack of) in a pipeline is generated every 3 months. The CRM program covers all cross-country pipelines in corrosive service.

ERM – Erosion Rate Monitoring: The purpose of this program is similar to the CRM but is aimed at monitoring erosion activity in 3-phase well lines. Production variables are the driving factor for this damage mechanism (i.e., production rates and solids loading);

therefore, inspection is determined by “triggers” such as velocity limits, well work, etc. If such triggers are exceeded, inspections are performed on daily, weekly, or monthly basis depending on the driving factor for placing the equipment at risk to erosion. Inspections are continued until confidence is gained that erosion is not occurring.

FIP – Frequent Inspection Program: The aim of this program is to manage mechanical integrity at locations where significant corrosion damage is classified. Locations are added to the FIP if they are approaching repair or derate criteria or if unusually high corrosion or erosion rates are detected. As the name implies, inspections are performed frequently until the item is repaired, replaced, derated, taken out of service, or corrosion/erosion rates reduced. The inspection interval varies, depending on how close the location is to repair/derate and the rate of corrosion but does not exceed 1 year. All equipment is covered by the FIP.

CIP – Comprehensive Integrity Program: This is an annual program and is aimed at detecting new corrosion mechanisms and new locations of corrosion as well as monitoring damage at known locations. The CIP therefore provides an assessment of the extent of degradation and the fitness-for-service. All equipment is covered by the CIP, although not all equipment is inspected annually. Primary elements of this inspection survey are:

- Repeat inspections on locations of known damage to evaluate equipment fitness for service.
- Quantify/qualify corrosion activity, measure performance of corrosion control, and determine whether corrective action is warranted.
- Sample new and/or old locations not recently inspected for new or unknown degradation.

The scope of the internal inspection program is relatively constant at approximately 65,000 inspection items per year. This includes both field and facility inspections.

Appendix 3.3.4 Corrosion Under Insulation

Corrosion under insulation is primarily associated with water ingress into the pipeline thermal insulation; in particular, at the field-applied insulation joints (weld packs).

The pipelines are generally uncoated carbon steel and are therefore vulnerable to external corrosion under the insulation (CUI) if water comes into contact with the pipe surface. The pipelines are constructed from either single or double joints (40 - 80 ft. long) with a shop-applied polyurethane insulation protected with a galvanized wrapping. The area around the girth welds are insulated with 'weld packs.' The detailed design of weld packs varies but all are prone to water ingress.

GPB Joint Design	Joint Type Freq	CUI Incident Rate
Anchor Joint	5.0%	3.5%
Damaged Insul	5.8%	0.5%
Missing Insul	1.6%	16.1%
Ell Anchor Joint	0.5%	5.4%
Ell Bottom Elev	5.1%	5.5%
Ell Bottom Elev Saddle	1.1%	8.5%
Ell Horiz Saddle	1.7%	13.3%
Ell Horizontal	9.8%	6.1%
Ell Top Elev	4.9%	1.4%
Ell Top Elev Saddle	0.8%	4.8%
Mid-Span Weld Pack	46.5%	2.9%
Saddle Joint	15.0%	6.2%
Vertical Joint	0.2%	2.6%
Wall Penetration	2.1%	1.2%
Average CUI Incident Rate		**4.1%**

Galvanized Spiral Wrap Clad, Foam-in-Place Polyurethane Insulation, data 2002 thru 2009

Table 7 shows the distribution of insulation joint types based on a sample of over 200,000 locations. For each specified joint type, there is an associated CUI incident rate. These data show there is as much variability in the CUI incident rate between the insulation joint configurations as there is associated with the service type. This suggests that the joint configuration and insulation joint location, along with age, have as much influence on the occurrence of external corrosion at weld-packs compared to the service type and operating temperature.

GPB Joint Design	Joint Type Freq	CUI Incident Rate
Anchor Joint	5.0%	3.5%
Damaged Insul	5.8%	0.5%
Missing Insul	1.6%	16.1%
Ell Anchor Joint	0.5%	5.4%
Ell Bottom Elev	5.1%	5.5%
Ell Bottom Elev Saddle	1.1%	8.5%
Ell Horiz Saddle	1.7%	13.3%
Ell Horizontal	9.8%	6.1%
Ell Top Elev	4.9%	1.4%
Ell Top Elev Saddle	0.8%	4.8%
Mid-Span Weld Pack	46.5%	2.9%
Saddle Joint	15.0%	6.2%
Vertical Joint	0.2%	2.6%
Wall Penetration	2.1%	1.2%
Average CUI Incident Rate		**4.1%**
Galvanized Spiral Wrap Clad, Foam-in-Place Polyurethane Insulation, data 2002 thru 2009		

Table 7 CUI Incident Rate by Joint Type

The main challenge in managing CUI is the detection of the external corrosion damage. Water ingress into the weld packs is a random process and therefore it is difficult to apply highly specific rules to target the inspection program.

Appendix 3.3.5 Below-grade Piping Integrity Program

The overall plan for the below-grade piping program is to employ the best available technology for inspection of below-grade piping segments where, historically, the prominent threat has been external corrosion. In-line inspection (ILI) is the preferred inspection technique for below-grade piping as it provides full volumetric metal loss examination of both internal and external corrosion. Anomalies identified during an ILI run may require manual nondestructive examination (NDE) follow-up, up to and including excavation. Where ILI technology cannot be employed, qualitative detection of cased piping is completed using long-range guided wave ultrasonic testing (LRGWUT) to provide a full volumetric screening of piping sections. Magnetostrictive sensors (MsS), a single-mode longitudinal guided wave has also been used in prior years. While MsS and LRGWUT are both proven technologies, LRGWUT has become the preferred method of inspection when ILI is not possible.

Appendix 3.3.6 Fitness for Service Assessment

The basic fitness-for-service criterion used by BPXA is ANSI/ASME B31G. The base document is the modified B31G, PRC 3-805, which is augmented with additional requirements defined in BP specification SPC-PP-00090, "Evaluation and Repair of Corroded Piping Systems".

Application of fitness-for-service is best illustrated by the following example and discussion using a typical 24" diameter, 375-mil wall thickness cross-country low-pressure (LP) flow line. The average depth of damage for this example is approximately 24% or 90 mils and average corrosion network length of 8.9". In calculating the corrosion rate to achieve this depth of damage, it was assumed that the corrosion rate is linear since the beginning of field life in 1977.

Figure 5 summarizes the dependence of Maximum Allowable Operating Pressure (MAOP) with the remaining wall thickness of a section of flow line based on ANSI/ASME B31G and is intended to show the multiple-layers of protection to the environment provided by the current fitness-for-service criteria. At the original wall thickness of 375 mils, the example flow line has a B31G calculated MAOP of 1400 psi. As the wall thickness is reduced by corrosion, this pressure containment capacity is also reduced.

Table 8 shows the MAOP for various wall thicknesses starting from the original wall thickness of 375 mils. It can be seen that the repair criterion used provide a significant level of conservatism over the minimum wall thickness required to retain the maximum operating pressure. In addition, high-level over-pressure protection provides additional protection over the normal operating pressure.

In addition to the depth of damage discussed, there are a number of other considerations that have to be accounted for when assessing fitness-for-service. Some of the concerns are,

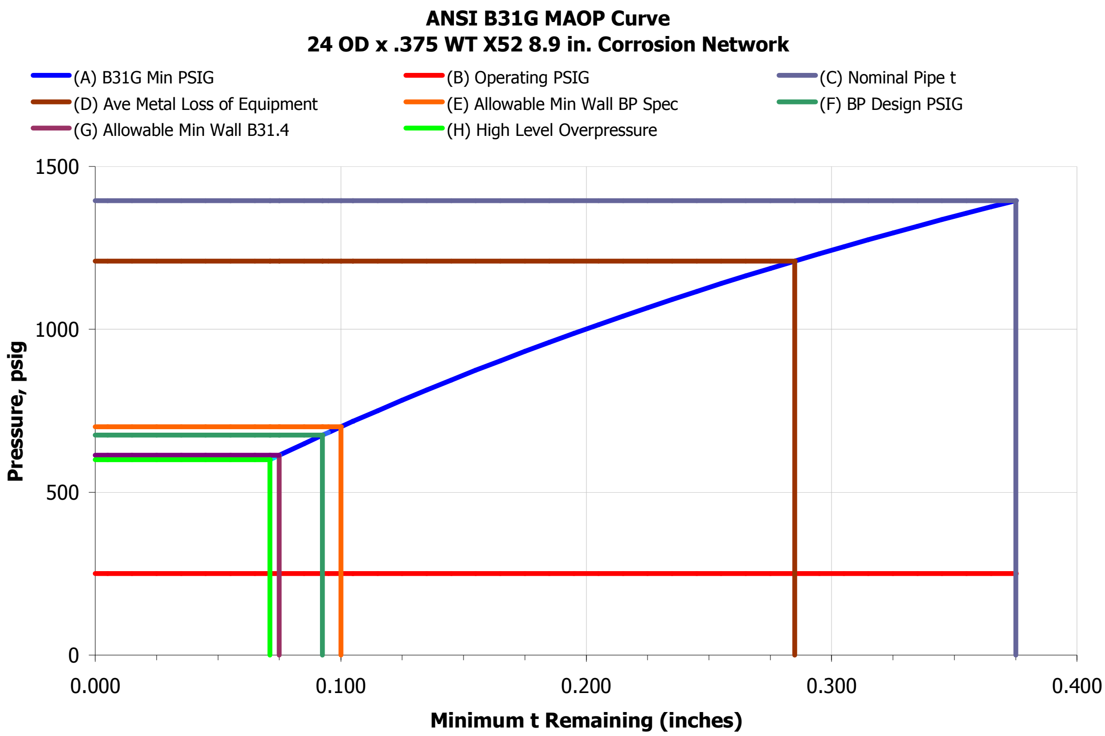
Localized/Pitting Corrosion Localized/pitting corrosion consisting of clearly defined relatively isolated regions of metal loss. The axial and circumferential extent of such regions needs to be determined and any potential areas of interaction where there is axial overlap between pitting regions.

General/Uniform Corrosion General corrosion consisting of widespread corrosion between islands of original material, again, as with pitting corrosion, the axial and circumferential extent of such regions need to be determined. The extent of damage is determined by the boundaries of good or non-corroded material surrounding the damaged area.

Interaction If more than one areas of metal loss exist in close proximity, the possible interaction between these corroded areas needs to be considered. The worst case for interaction of several corroded areas is that a composite of all the profiles within a given metal-loss area needs to be considered.

Critical Dimensions The critical dimensions of metal loss, whether internal or external corrosion damage, need to be determined depending on the corrosion damage morphology described above. The most important dimensions are the axial or longitudinal length, and the maximum depth of damage.

Evaluation of Corroded Pipe The evaluation of corroded pipe involves determining the remaining strength and safe operating pressure on the basis of the overall axial length, circumferential extent, and maximum depth of the corroded area.



	Legend	Description/Comments
(A)	B31G Min PSIG	The relationship between maximum allowable operating pressure, MAOP, as given by B31G and the remaining wall thickness
(B)	Operating PSIG	The normal operating pressure for a typical low pressure common line or flow line (CL/LDF)
(C)	Nominal Pipe t	The original nominal pipe wall thickness which for this example is 0.375" (375 mils) as is the case for many of the flow lines at GPB
(D)	Ave metal loss	From the inspection data an average pit depth or depth of damage across the field for the 24" LP OIL flow lines
(E)	Min Wall BP Spec	The minimum wall thickness, 0.100", which is permitted under BP specification SPC-PP-00090 for the management of corroded pipe-work. Any location at or below this level is actioned regardless of the calculated MAOP
(F)	BPXA Design PSIG	The original design pressure that the pipe wall thickness was designed to retain
(G)	Allowable Min Wall	Allowable minimum wall thickness under B31 below which a repair is mandated by code
(H)	High level P protection	High level over-pressure protection for the LP systems as either a pressure switch or the PSVs on the separator/slug-catcher

Figure 5 MAOP versus Remaining Wall Thickness

Step	t, mils	MAOP	Curve	Description
1	375	1395	(C)	As constructed pipe condition with no corrosion or degradation of wall thickness
2	285	1209	(D)	After 25+ years of service the average wall loss for the flow line system is 24% or 90 mils and has a MAOP of 1209 psi. This is an equivalent corrosion rate of 4 mpy. At the average corrosion rate seen to date, in approximately 50 years the wall loss will be such that it reaches the repair criteria in Step 3. Note that the target corrosion rate is 2 mpy to provide additional protection and scope for extended field life.
3	100	700	(E)	The BP repair criterion from BP Specification SPC-PP-00090 is 100 mils with an MAOP of 700 psi. This repair criterion is 25 psi above the design pressure and 25 mils or 33% above minimum wall thickness defined by code B31G giving significant level of additional protection
4	95	675	(F)	The original system design pressure
5	75	614	(G)	The minimum wall thickness allowed under B31G for this application which is 80% wall loss regardless of pressure
6	71	600	(H)	High level over-pressure protection for the low pressure production system at Greater Prudhoe Bay
7		250	(B)	The normal operating pressure for the system

Table 8 Thickness, MAOP Correlation

Figure 6 illustrates the FFS envelop for a combination of depth and length of defect as defined in BP Specification SPC-PP-00090. As can be seen from the curve, the criteria for allowable operating service condition is more conservative than the industry standard at the low end of the remaining wall thickness. This conservatism reflects two issues, (a) the need to provide a margin for error in the determination of wall thickness and corrosion rate, and hence remaining life, and (b) the decreased accuracy of the NDE techniques in use at a wall thickness of less 100 mils.

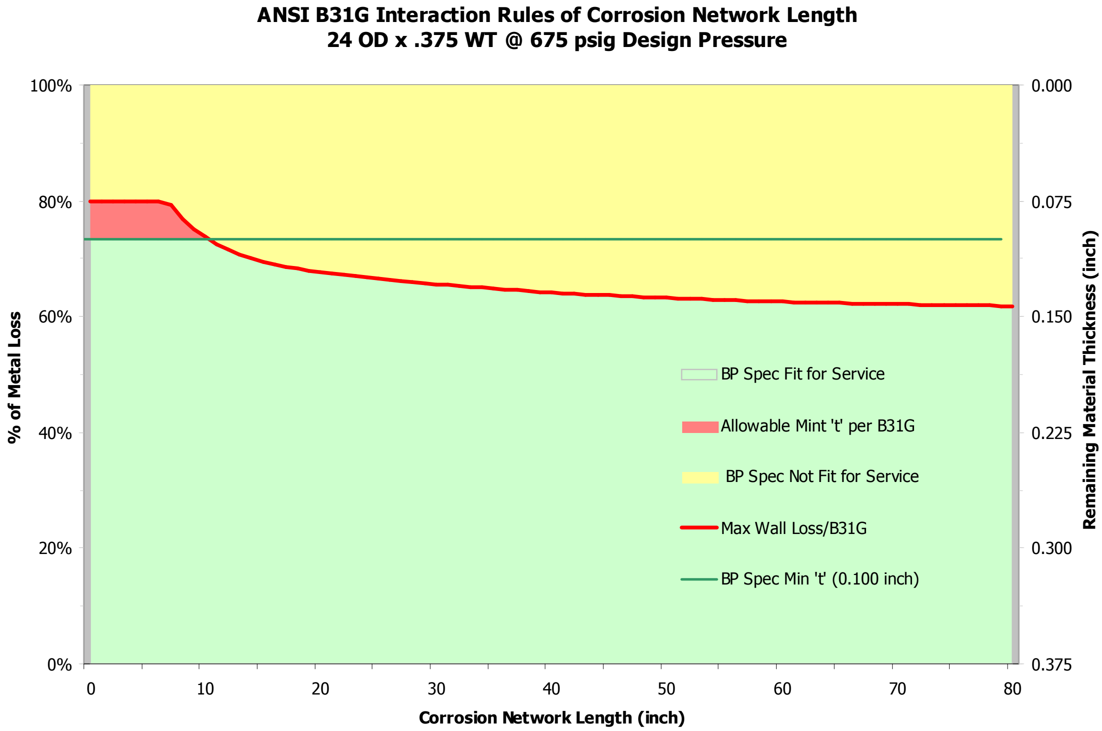


Figure 6 Fitness-for-Service Envelope Based on BP SPC-PP-00090

In addition, repairs are typically scheduled when the corrosion damage has reached 105% of the repair criteria. This additional conservatism is in order to allow repairs to be planned rather than requiring an immediate plant shutdown.

In summary, the current equipment FFS assessment for piping accounts for two major elements, whichever is the greater remaining wall thickness of the assessment criteria.

- Remaining strength of material is sufficient to contain internal pressure as calculated by ANSI/ASME B31G/modified B31G methodology,
- Minimum thickness, regardless of pressure retaining calculation, is equal to the greater of 0.100 inch or 20% remaining wall thickness.

These same criteria are applied to remaining flow and well lines with the appropriate characteristics and parameters.

Appendix 3.3.7 In-line Inspection

In-line inspection (ILI) tools, or smart pigs, are used where pigging facilities and process environment allow for technical and cost effective performance within the capabilities of the instruments. Magnetic flux leakage (MFL) type tools are the most commonly used by BPXA.

It is important to note that because the vast majority of the cross-country flow lines are above ground, the value of ILI data is considerably lessened as compared with buried or underground systems. The primary value of ILI data is in the initial identification and location of damaged locations within a pipeline system. Having initially identified the location of damaged areas, the long-term integrity, pipeline condition and current corrosion rate, of the flow line can be more effectively managed through the use of targeted manual NDE techniques.

Having established the condition and location of damaged sections of line the locations are then added to the routine NDE program where the condition and fitness-for-service is determined and where the on-going corrosion rate and level of corrosion mitigation can be monitored.

There are also limitations with ILI technology. A typical high resolution[12] MFL smart pig gives wall thickness measurements that are ±10% of the nominal wall thickness and sizing resolution of 3 times wall thickness for length and width assessment. In addition, there are temperature and pressure limitations that prevent or make difficult the use of MFL tools in many lines on the North Slope. For example, the typical upper operating temperature for the MFL tools is 122°F/50°C compared with a typical separator fluids temperature of 150-160°F/65-71°C.

While the ILI program is an important element in the overall corrosion and integrity management program, it should be considered like any other inspection or monitoring technique as simply another tool to be applied where it delivers the most value.

When used, smart pig inspections are performed to gain a relative understanding of pipeline condition and rate of deterioration and/or to provide confidence that the internal and external conventional inspection programs have identified locations where mechanical integrity is at risk. Results from in-line inspections are not reported "as received" directly from the smart pig service company but are reported as part of the overall NDE summary.

Areas identified by ILI and interpreted as being a risk to future operation of equipment, are verified through visual, radiographic and/or ultrasonic inspection techniques and the results are reported as part of routine inspection programs.

[12] MFL manufacturer technical data sheet

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.0 Overall program goals	Eliminate corrosion/erosion related failures	No harm to people No accidents No damage to environment Regulatory compliance Compliance with industry standards	Integrated program with monitoring, inspection, operational controls, and corrosion inhibitor	Key performance indicators Leading and lagging indicators	Adjust mitigation, monitoring, and operational targets to meet objective Defect elimination - repair/replace/abandon
	Provide equipment availability to end of Field life	2050	Integrated Program with Monitoring, Inspection, Operational Controls, and Corrosion Inhibition	Key Performance Indicators Leading and Lagging Indicators	Adjust Mitigation, Monitoring, and Operational Targets to Meet Objective
	Cost effective Corrosion Management	Budget	Alliance Partnerships Technical Incentive Contracts Continuous Improvement	Key Performance Indicators Leading and Lagging Indicators	Develop more Cost Effective Methods For Delivering the Program Best in Class Technology Investment for the Future

Table 9 Corrosion Management System

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.1 Corrosion Monitoring	Monitor for changes in corrosion rates	• System dependant targets • Corrosion rate to meet overall objectives • Regulatory compliance • Compliance with industry standards	• Short term corrosion rate determination • Medium term corrosion rate determination	• ER probes • Weight loss coupon rate • Pitting Rates	• Adjust Mitigating action to achieve corrosion rate target
	Monitor effectiveness of the chemical mitigation programs	• Optimize Corrosion Inhibitor Rates and Distribution • Optimize chemical mitigation programs e.g. • Oxygen scavenger • Biocide • Drag reducing agent • Scale	• See above	• See above	• Provide feedback to • Chemical treatment • Operations • Inspection activities • Adjust Mitigation Effort • Production Chemistry
	Monitor changes in the process conditions	• Field-wide Velocity Management targets	• Weekly Review of Operational Controls by CIC Group • Operations review of fluid velocities • Velocity alarms in Distributive Control System (DCS)	• Mixture Velocities, Water Cuts, and Water Rates	• Adjust production rates to meet velocity management targets
	Corrosion mechanism changes with time	• Mitigation action in place prior to threat to mechanical integrity	• Data availability and access • Ease of 'data mining' and evaluation • Single data storage • Comprehensive data management and reporting process	• Long-Term Process Change	• Develop mitigation program • Mechanism management as part of routine business
1.2 Erosion Monitoring	Monitor the effectiveness of the erosion mitigation programs	• V/Ve <2.5 • Max mixture Velocity and water cut matrix • Well Put-On-Production (POP) process • Regulatory compliance • Compliance with industry standards	• Unified velocity management standard across the North Slope • Monthly compilation Of High Risk Wells • Inspection of High Risk Wells • Mixture velocity calculation in DCS	• Mixture Velocities • Inspection results	• Additional inspection and monitoring at high risk sites • Adjust Process Conditions • Well shut-in • Production reduction • Design/debottleneck facilities

Table 10 Corrosion Management System Element – Monitoring

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.3 Corrosion Mitigation	Mitigate Corrosion Through Application of Corrosion Inhibitors	• Control Corrosion Rates to Acceptable Levels (See Overall Program Goals) • Regulatory compliance • Compliance with industry standards	• Continuous Injection into individual wells as far upstream as possible - currently at Wellhead • Protect all equipment between injection point and separation plant	• ER Probes • WLC's • Inspection	• Corrosion Inhibitor Development • Adjust Mitigation Effort
		• Control Corrosion Rates to Acceptable Levels (See Overall Program Goals)	• Batch Treatments on a routine schedule with injection at the Wellhead	• WLC's • Inspection	• Corrosion Inhibitor Development • Adjust Mitigation Effort Through Reviews
	Mitigate Corrosion through Operational Controls	• Operational Guidelines	• Weekly Reviews by CIC Group	• Mixture Velocities	• Adjust Process Conditions
	Mitigate Corrosion through Maintenance Pigging	• Achieve Scheduled Frequency	• Maintenance Pigging	• Inspection • Pigging Returns	• Adjust Maintenance Pigging Schedule
1.4 Erosion Mitigation	Mitigate Erosion Through Operational Controls and Design	• Control Erosion Rates to Acceptable Levels (See Overall Program Goals) • V/Ve < 2.5 • Regulatory compliance • Compliance with industry standards	• Well POP process • V/Ve Guidelines	• V/Ve • Inspection (ERM)	• Adjust Process Conditions

Table 10 (continued) Corrosion Management System Element – Mitigation

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.5 Inspection	Integrated inspection program to provide a overall assessment of plant condition and corrosion rates	• Inspection activity level • Leak/save target • Inspection increases • Plant condition • Regulatory compliance	• Corrosion rate monitoring program (CRM) • Erosion rate monitoring program (ERM) • Comprehensive inspection program (CIP) • Frequent inspection program (FIP) • Corrosion under insulation program (CUI)	• NDE technique sheets and procedures • Standardized assessment of piping condition, degradation rate and mechanism	• Provide feedback to chemical mitigation program • Erosion management program • Fitness for service assessment • Equipment life assessment • Proactive repair scheduling
	Assessment of Current Damage Mechanisms	• Zero Increases	• Internal and external programs	• See above	• Repair/replace/monitor
	Search for New Damage Mechanisms	• Mitigation action in place prior to threat to FFS	• Baseline new equipment • Apply lessons learnt from industry practice else where in the world • Apply lessons learned for other BP operations • Apply learnings across the field for similar equipment/process conditions • Communications with Operations and Reservoir Engineers	• See above	• Develop mitigation program • Mechanism management as part of routine business
1.6 Fitness for Service	Fitness for service assurance	• Regulatory compliance • Compliance with industry standard	• See above inspection programs	• Battelle Modified B31G fitness-for-service criteria (note piping only) • BP internal specification for the assessment of damaged pipe	• Repair equipment • Replace equipment • Derate equipment • Abandon equipment
	Structural integrity	• Regulatory compliance • Compliance with industry standard	• Walking speed survey every 5 years	• Piping design code BP Spec, B31.4 and B31.8 • Piping stress analysis • Nondestructive testing as required	• Repair/replace • Correct support defect • Monitor for further degradation

Table 10 (continued) Corrosion Management System Element – Inspection

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.7 Continuous Improvement	Provide Feedback to Monitoring, Mitigation, and Inspection Programs	• Continuous Improvement	• Integrated Program with Monitoring, Inspection, Operational Controls, and Corrosion Inhibitor • Provides Feedback Control Loop for Program Improvements • Consolidated data store, MIMIR	• Weekly program review • Quarterly program review • Annual program reviews and strategy assessment • Annual equipment life/availability review • Key Performance Indicators	• Strategic adjustment • Budget/funding level changes • Mitigation process change and review • Technical/R&D requirements and programs

Table 10 (continued) Corrosion Management System Element – Inspection

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.1.1 Monitoring – Electrical Resistance Probes (ER)	Monitor the Effectiveness of the Mitigation Programs	• < 2mpy • Regulatory compliance • Compliance with industry standard	• ER Probes - Upstream and/or Downstream Ends of Flow lines	• Investigate Cause for Corrosion Rate Increase •	• Mitigation Adjustments • ER Probe Maintenance
1.1.2 Monitoring – Weight Loss Coupons (WLC)	Monitor the Effectiveness of the Mitigation Programs	• Gen CR: < 2mpy • Pit CR: < 20mpy • Regulatory compliance • Compliance with industry standard	• WLC – Installed Flow lines, Well lines, Headers, and Piping	• Investigate Cause for Corrosion Rate Increase	• Mitigation Adjustments • Inspection Program Adjustments
1.1.3 Monitoring – Process Conditions	Monitor changes in the Process Conditions	• (See Mixture Velocity and Erosion Sections Below) • Regulatory compliance • Compliance with industry standard		• Investigate Cause for Process Upset • Long-Term Process Change • Monitor Impact •	• Mitigation Adjustments
1.1.4 Monitoring – Mixture Velocity Management Program	Monitor the Effectiveness of the Mitigation Programs	• Operational Guidelines • Mix Vel Limits • Regulatory compliance • Compliance with industry standard	• Operations Acceptance of Mixture Velocity Guidelines • SETCIM	• Review Alarm List to Determine True Offenders	• Adjust Process Conditions
1.1.5 Monitoring – Erosion Management Program	Monitor the Effectiveness of the Erosion Mitigation Programs	• Operational Guidelines • Well Put on Production (POP) • V/Ve < 2.5 • Regulatory compliance • Compliance with industry standard	• Operations Acceptance of Erosion Guidelines • High Risk Well Inspection Program (ERM)	• Monthly Reviews to Determine High Risk Equipment and Repeat Offenders	• Adjust Process Conditions

Table 11 Monitoring Program Techniques

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.2.1 Mitigation – Corrosion Inhibitor	Mitigate Corrosion Through Application of Corrosion Inhibitors	• Control Corrosion Rates to Acceptable Levels (See Overall Program Goals) Regulatory compliance • Compliance with industry standard	• Continuous Injection Into Individual Wells as Far Upstream As Possible – Currently at Wellhead • Protect All Equipment Between Injection Point and Separation Plant	• ER Probes • WLC's • Inspection	• Corrosion Inhibitor Development • Adjust Mitigation Effort
		• Control Corrosion Rates to Acceptable Levels (See Overall Program Goals)	• Batch Treatments on a Routine Schedule with Injection at the Wellhead	• WLC's • Inspection	• Corrosion Inhibitor Development • Adjust Mitigation Effort through Reviews
1.2.2 Mitigation – Operational Control, Maintenance, and Material Selection	Mitigate Corrosion Through Operational Controls	• Operational Guidelines • Mixture Velocity Limits • Regulatory compliance • Compliance with industry standard	• Operations Acceptance of Mixture Velocity Guidelines	• Mixture Velocities • Review Alarm List to determine true offenders	• Adjust Process Conditions
	Mitigate Erosion through Operational Controls	• Operational Guidelines • Well POP • V/Ve < 2.5	• Operations Acceptance of Erosion Guidelines • High Risk Well Inspection Program (ERM)	• Monthly Reviews to Determine High Risk Equipment and Repeat Offenders	• Adjust Process Conditions
	Mitigate Corrosion through Maintenance Pigging	• Achieve Scheduled Frequency	• Maintenance Pigging	• Inspection • Pigging Returns	• Adjust Maintenance Pigging Schedule
	Corrosion Resistant Alloys	• Zero Increases (I's)	• Selected Facilities & Equipment	• Inspection • Applicability For Service Requirements	• Replace as Necessary
1.2.3 Mitigation – Structural Integrity	Mitigate structural damage caused by subsidence, jacking, vibration, impact, snow loading, etc. through inspections	• No failures due to structural damage • Regulatory compliance • Compliance with industry standard	• Operational procedures for visual surveillance of pipelines • Piping stress analysis as required • NDE inspections as required	• Review Pipeline Design Code/BP Specification	• Repair, replace and correct deficiencies as required • Add Pipeline Vibration Dampeners (PVDs) as required

Table 11 (continued) Mitigation Program Techniques

Program	Plan/Objectives	Target	Implementation	Evaluation	Corrective Action
1.3.1 Corrosion Rate Monitoring (CRM)	Assessment of current corrosion mechanisms Monitor for new corrosion mechanisms	• No measurable active corrosion -Zero increases (I's) • Regulatory compliance • Compliance with industry standard	• CRM Program – Fixed locations on approximately bi-annual frequency	• Inspections • Condition of Equipment • Rate of degradation	• Mitigation Adjustments • Repair/Replace Preventative Maintenance
1.3.2 Erosion Rate Monitoring (ERM)	Monitor high risk wells Assessment of current erosion locations	• Manageable rate of degradation • Regulatory compliance • Compliance with industry standard	• ERM Program – monthly to quarterly	• Inspections • Condition of Equipment • Rate of degradation	• Mitigation Adjustments • Repair/Replace Preventative Maintenance
1.3.3 Frequent Inspection Program (FIP)	Assessment of High Corrosion Rates Monitor locations near repair	• Fitness-for-Service • Regulatory compliance • Compliance with industry standard	• FIP Program – monthly to bi-annual	• Inspections • Condition of Equipment • Rate of degradation	• Mitigation Adjustments • Repair/Replace Preventative Maintenance
1.3.4 Comprehensive Integrity Program (CIP)	Comprehensive Coverage of equipment Fitness-for-Service review	• Fitness-for-Service • Regulatory compliance • Compliance with industry standard	• CIP – Condition and rate based half-life recurring frequency • Extend coverage through new locations	• Inspections • Condition of Equipment • Rate of degradation	• Mitigation Adjustments • Repair/Replace Preventative Maintenance
1.3.5 Corrosion Under Insulation (CUI)	Comprehensive Coverage of equipment	• Inspection of Locations susceptible to CUI • Fitness For Service • Regulatory compliance • Compliance with industry standard	• CUI – Risk based annual program • Management of location inventory through recurring examinations	• Detect Damage Areas • Analysis of occurrence	• Repair/Replace Preventative Maintenance

Table 11 (continued) Mitigation Program Techniques

Method	Technique	Description	Sensitivity	Accuracy	Freq	Notes/Comments
Corrosion Monitoring	Electrical Resistance (ER) Probes	Measurement of corrosion rate by monitoring changes in electrical resistance of a metal probe due to volume loss	High	Low	H/D	Correlate poorly to actual pipewall corrosion rates
	Weight Loss Coupons Corrosion Rate	Exposure of metal samples to corrosive fluid and calculation of volume loss rates based on weight	Medium	Medium	M	Limited benefit in determining short-term effects, such as flow regime changes on corrosion rates
	Weight Loss Coupons Pitting Rate	Exposure of metal samples and assessment of pitting rate via measurement of pit depths	Medium	Medium	M	Not a very sensitive measure for GPB 3phase but more effective in the PW system
	Galvanic Probe	Detects changes in corrosivity as a function of current flow between two dissimilar metals.	High	Low	C	Not a reliable measurement of mild steel corrosion rate. Very suitable to monitor oxygen and chlorine changes in seawater
	Linear Polarization Resistance (LPR)	Electrochemical technique for assessing corrosion rate by application of controlled voltage and measuring current response	High	Low	H/D	Not used due to the interference of hydrocarbon films on measurement

Table 12 Corrosion Monitoring Techniques – Benefits and Limitations

Method	Technique	Description	Sensitivity	Accuracy	Freq	Notes/Comments
Process Monitoring	Mixture velocity	Mixture velocity of fluids in pipe-work	Medium	Medium	D	Accuracy dependent upon production information (T, P, Oil, Water, Gas)
	Water cut	Percent water in liquid fluids	Medium	Medium	D	Accuracy dependent upon production information (Oil, Water)
	Temperature and pressure	Measured temperature and pressure in process equipment	Medium	Medium	D	
	Dissolved Oxygen	Amount of oxygen dissolved in Sea Water	High	Medium	D	In-line accuracy problematic. Chemets® method more accurate
	Iron (Fe) counts	Amount of Iron (Fe) dissolved in process water	High	Low	M	
	Microbiological activity	Amount of microbiological life forms in process fluids	Medium	Low	M	

Table 13 Process Monitoring techniques – Benefits and Limitations

Method	Technique	Description	Sensitivity	Accuracy	Freq	Notes/Comments
Inspection/NDE	Radiographic Testing (RT)	Assessment of pipe wall degradation by passing gamma or x-ray radiation through a specimen and projecting an image on conventional lead screen/film. Irregular density variations of the image can indicate metal loss.	Medium	Medium	M/Q/H/Y	Utilized for detection, monitoring, and fit for service assessment of pipe metal loss in the form of mechanical, corrosion, and erosion degradation. Currently being phased out in lieu of 'greener' process of DRT – see below
	Digital Radiographic Testing (DRT)	Assessment of pipe wall degradation by passing gamma or x-ray radiation through a specimen and projecting an image on phosphor screen/imaging plate. Irregular density variations of the image can indicate metal loss.	Medium	Medium	M/Q/H/Y	Utilized for detection, monitoring, and fit for service assessment of pipe metal loss in the form of mechanical, corrosion, and erosion degradation. DRT provides additional benefits in waste reduction associated with conventional film and processing chemicals
	Tangential Radiography Testing (TRT)	Assessment of pipe wall degradation by passing gamma or x-ray radiation through insulation at the tangent of the specimen and projecting an image on screen/film, phosphor screen/imaging plate, or detector array.	High	Low	Y	Utilized for detection of corrosion under insulation (CUI). Deployed where potential moisture ingress is suspected on thermally insulated piping
	Ultrasonic Testing (UT)	Assessment of pipe wall thickness by sending/receiving ultrasound through a specimen. Echoes returning indicate remaining thickness of the specimen.	Medium	High	M/Q/H/Y	Utilized for detection, monitoring, and fit for service assessment of pipe metal loss in the form of mechanical, corrosion, and erosion degradation
	LRGWUT Ultrasonic Testing (LRGWUT)	Volumetric assessment of pipe wall by sending/receiving ultrasound through a specimen in the form of cylinder Lamb Waves. Monitoring changes in these waves indicate potential changes in pipe thickness. Alternatively, echoes returning to the source transducer may also indicate interruptions or pitting in the pipe segment.	Low	Low	Y	Utilized for cased piping assessment where access does not support use of traditional inspection methods. The method is capable of semi-quantifying metal loss but cannot discriminate between internal and external corrosion
	Electromagnetic Pulse Testing (EMT)	Assessment of pipe wall by propagating broadband electromagnetic waves on the exterior surface of the specimen. When waves traveling down steel pipe encounter corrosion on the pipe surface, the waves are distorted. Distortions in waveform may indicate rust by-product on the surface of the steel and subsequent metal loss.	High	Low	Y	Utilized for cased piping assessment where access does not support use of traditional inspection methods. The method cannot quantify metal loss and has a tendency to report false positive results but seldom overlooks surface atmospheric corrosion

Table 14 Inspection/Non-Destructive Examination Techniques – Benefits and Limitations

Method	Technique	Description	Sensitivity	Accuracy	Freq	Notes/Comments
Inspection/NDE (Cont)	In-line Inspection – Smart Pig Magnetic Flux (MFL) Technique	Assessment of pipelines for the detection and measurement of metal loss. These pigs carry high strength magnets, which apply a strong magnetic field into the pipe wall. The magnetic field saturates the pipe steel with magnetic flux. As a result, areas of metal loss cause the flux to leak out of the pipe wall. The flux leakage data is recorded and used to infer the size and depth of any metal loss defects in the pipe.	High	Medium	N/A	Utilized where design and process operation permit in-line pigging. Metal loss MFL In-line Inspection provides complete evaluation of pipeline integrity within the limitations of the MFL technique.

Table 14 (continued) Inspection/Non-Destructive Examination Techniques – Benefits and Limitations

Service	Equipment Type	Monitoring Technique	Inspection Program	Mitigation Program*
Oil	Flow line	• ER Probes • WLC • Process Monitoring	• CRM • FIP • CIP • CUI	• CI Injection • Mixture Velocities • Periodic Maintenance Pigging • Operational Controls
	Well line	• WLC • Process Monitoring	• CRM • ERM • FIP • CIP • CUI	• CI Injection • Mixture Velocities • Mixture Velocities • Operational Controls
Produced Water	Flow line	• WLC	• CRM • FIP • CIP • CUI	• CI Injection • CI Carry Over • Periodic Maintenance Pigging • Mixture Velocities • Operational Controls
	Well line	• WLC	• CRM • FIP • CIP • CUI	• CI Injection • CI Carry Over • Mixture Velocities • Operational Controls
Seawater	Flow line	• WLC • Galvanic Probes • Dissolved 02 • Microbiological Activity	• CRM • FIP • CIP • CUI	• Biocide Treatment • 0_2 Scavenger • Periodic Maintenance Pigging • Operational Controls
	Well line	• WLC • Microbiological Activity	• CRM • FIP • CIP • CUI	• Biocide Treatment • Periodic Maintenance Pigging • Operational Controls
Export oil	Flow line	• WLC • ER Probes	• CRM • FIP • CIP • CUI	• CI Carry Over • Mixture Velocities • Operational Controls • Periodic Maintenance Pigging

*Applicable to all inspection programs noted

Table 15 Corrosion Management System Implementation by Equip Type and Service

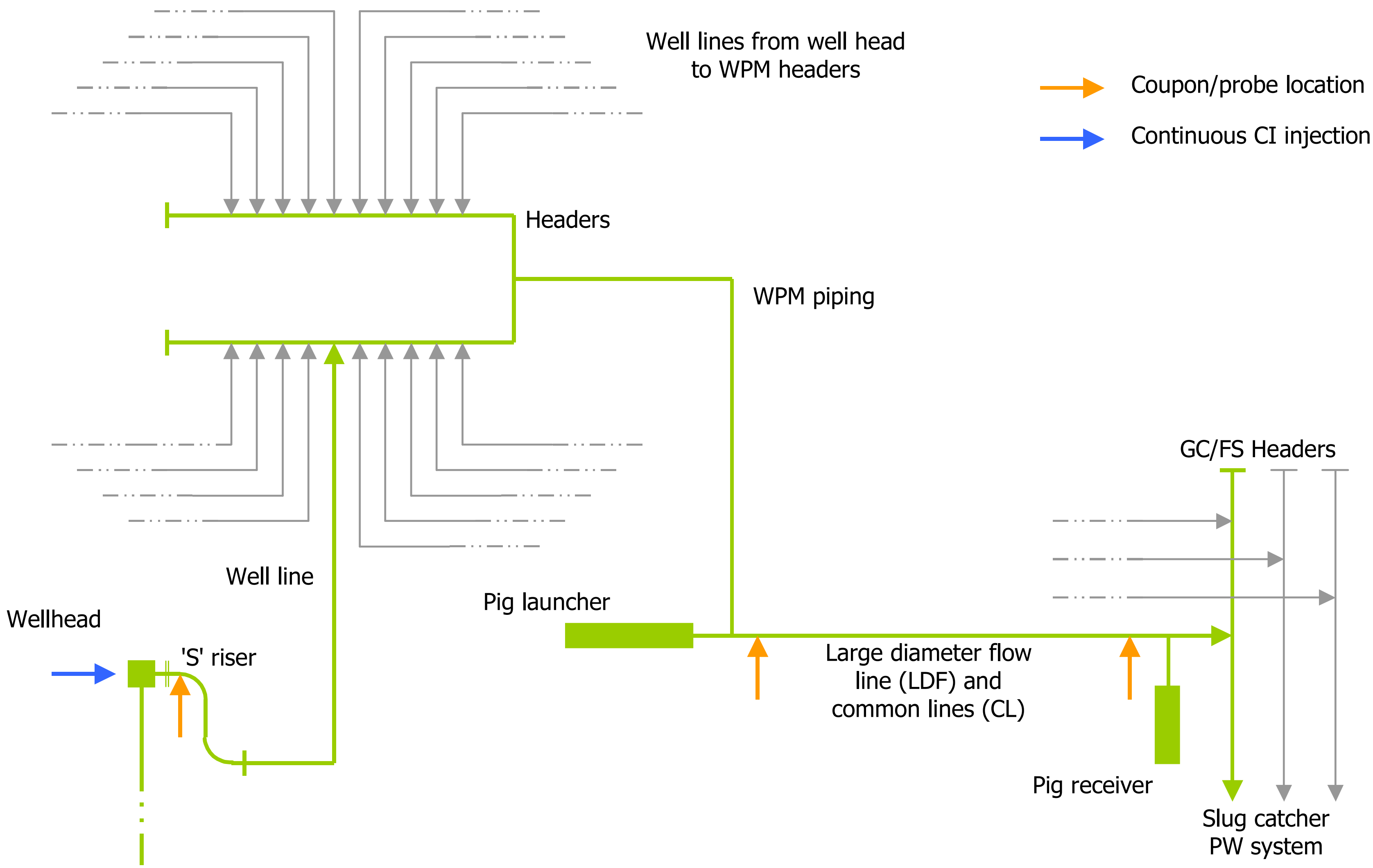


Figure 7 Facility Schematic

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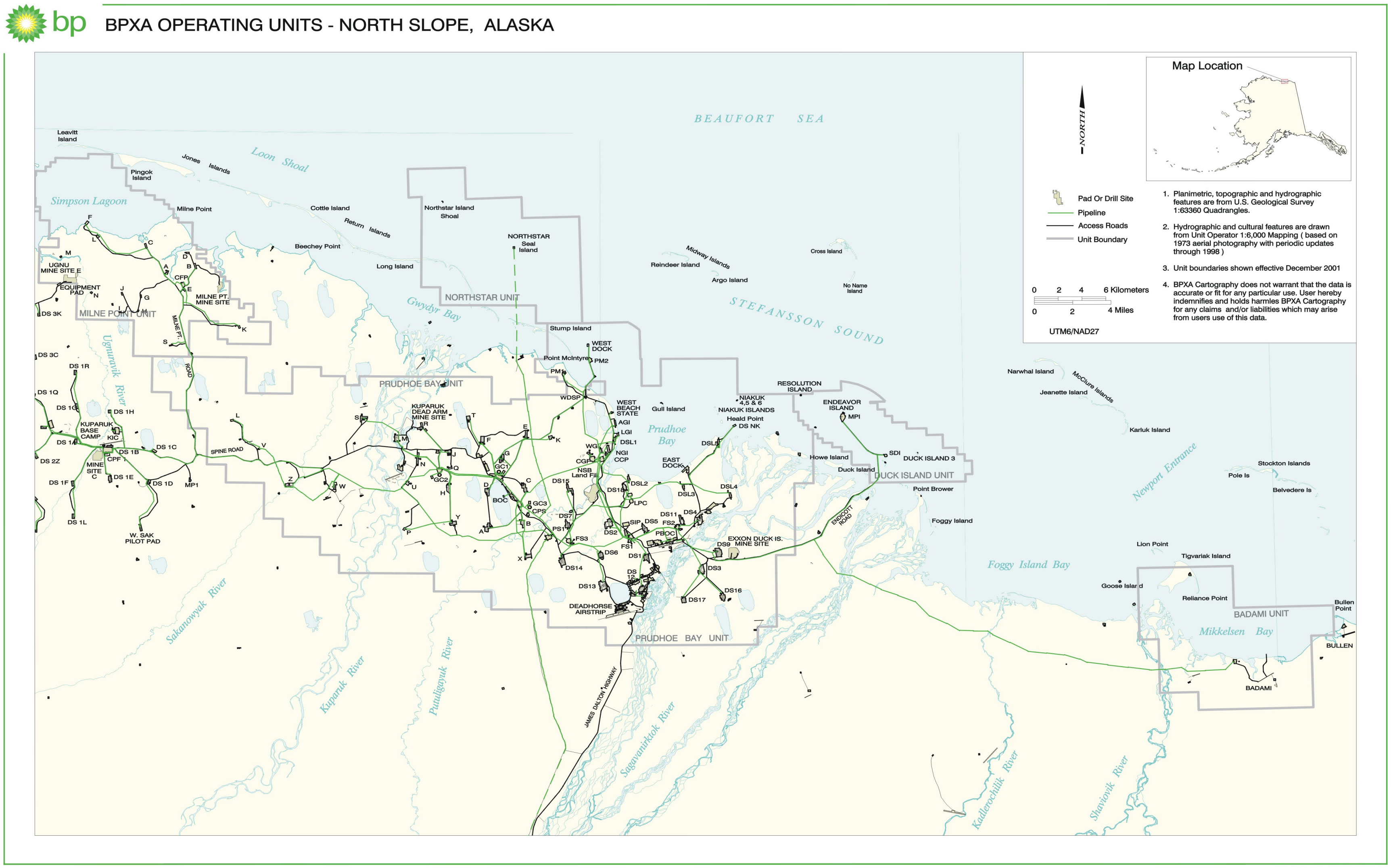

Figure 8 Map of North Slope

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BP North Slope Operations	Field Data (updated 2008)[13]	
Greater Prudhoe Bay	Field Area (incl. satellites)	213,543 acres
	Original Oil in Place (Gross)	25 billion barrels
	Original Gas in Place (Gross)	45 trillion Std. Cu Ft
	Oil Production Wells	1,128
	Gas Injection Wells	34
	Water Injection Wells	88
	Major Separation Plants	6
	Major Gas Handling Plants	2
	Major Water Handling Plants	3
	Miles of Pipelines (approximate)	1,300
Midnight Sun	Field Area	3,112 acres
	Original Oil in Place (Gross)	0.6 billion barrels
	Original Gas in Place (Gross)	0.1 trillion Std Cu Ft
	Oil Production Wells	2
	Water Injection Wells	3
	Miles of Pipelines (approximate)	4
Aurora	Field Area	7,519 acres
	Original Oil in Place (Gross)	0.1 billion barrels
	Original Gas in Place (Gross)	0.1 trillion Std Cu Ft
	Oil Production Wells	20
	Water Injection Wells	11
	Miles of Pipelines (approximate)	1
Pt. McIntyre	Field Area	10,834 acres
	Original Oil in Place (Gross)	0.8 billion barrels
	Original Gas in Place (Gross)	0.9 trillion Std Cu Ft
	Oil Production Wells	61
	Gas Injection Wells	1
	Water Injection Wells	9
	Miles of Pipelines (approximate)	6
Lisburne	Field Area	79,929 acres
	Original Oil in Place (Gross)	1.8 billion barrels
	Original Gas in Place (Gross)	0.3 trillion Std Cu ft
	Oil Production Wells	79
	Gas Injection Wells	4
	Major Separation Plants	1
	Miles of Pipelines (approximate)	27

[13] Source publication “BP in Alaska” fact book printed July 2009.

BP North Slope Operations	Field Data (updated 2008)[13]	
Niakuk & Western Niakuk	Field Area	6,443 acres
	Original Oil in Place (Gross)	0.2 billion barrels
	Original Gas in Place (Gross)	0.1 trillion Std Cu Ft
	Oil Production Wells	18
	Water Injection Wells	7
	Miles of Pipelines (approximate)	6
Milne Point - Kuparuk Schrader-Bluff[14]	Field Area	49,668 acres
	Original Oil in Place (Gross)	0.92 billion barrels
	Oil Production Wells	149
	Gas Injection Wells	1
	Water Injection Wells	70
	Major Separation Plants	1
	Miles of Pipelines (approximate)	55
Eider	Field Area	690 acres
	Original Oil in Place (Gross)	0.015 billion barrels
	Original Gas in Place (Gross)	0.052 trillion Std Cu Ft
	Oil Production Wells	2
	Miles of Pipelines (approximate)	0.5
Endicott	Field Area	17,547 acres
	Original Oil in Place (Gross)	1.1 billion barrels
	Original Gas in Place (Gross)	1.2 trillion Std Cu Ft
	Oil Production Wells	58
	Gas Injection Wells	5
	Water Injection Wells	18
	Major Separation Plants	1
	Miles of Pipelines (approximate)	52
Sag Delta North	Field Area	1,150 acres
	Original Oil in Place (Gross)	0.014 billion barrels
	Oil Production Wells	2
	Water Injection Wells	2
	Miles of Pipelines (approximate)	0.5
Badami	Original Oil in Place (Gross)	0.160 billion barrels
	Oil Production Wells	6
	Gas Injection Wells	2
	Major Separation Plants	1
	Miles of Pipelines (approximate)	50

[14] Milne-Kuparuk is a separate and distinct unit from the large Kuparuk River Field, but produces from some of the same reservoir sands.

BP North Slope Operations	Field Data (updated 2008)[13]	
Northstar (current 3/02)	Field Area	17,682 acres
	Original Oil in Place (Gross)	0.176 billion barrels
	Oil Production Wells	20
	Gas Injection Wells	6
	Water Injection Wells	2
	Major Separation Plants	1
	Miles of Pipelines (approximate)	30

Table 16 BPXA North Slope Operations

BP Exploration (Alaska) Inc.
Corrosion, Inspection and Chemicals (CIC) Group
900 E Benson Boulevard
Anchorage, Alaska 99519